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FUEL COST ESCALATION STUDY.(U)

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Fuel Cost Escalation Study

by

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and

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Propulsion Development Department

APRIL 1977

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Naval Weapons Center

CHINA LAKE, CALIFORNIA 93555

Naval Weapons Center

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R. G. Freeman, III, RAdm., USN . . . . Commander
G. L. Hollingsworth . . . . Technical Director

FOREWORD

This report, which supersedes NWC Technical Memorandum 2950, presents the results of work performed during the period January-October 1976. The goal was to provide the Navy with projections of the prices it will have to pay for different energy forms during the next 45 years. This effort was supported by the Civil Engineering Laboratory, Naval Construction Battalion Center, Port Hueneme, California, under Work Request 6-0136 dated 9 January 1976.

This report was reviewed for technical accuracy by Duane H. Williams.

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(U) *Fuel Cost Escalation Study* (U), by Ellis E. Kappelman, Stephen M. Lee, Ruth F. Klever, and D. R. Cruise. China Lake, Calif., Naval Weapons Center, April 1977, 128 pp. (NWC TP 5958, publication UNCLASSIFIED.)

(U) A fuel and energy cost escalation study was conducted to provide a projection of the costs of fuel oil, natural gas, coal and electricity to the year 2020. Upper and lower limits on probable prices are provided as well as most probable prices. These price projections were made based on examination of the nation's energy use, growth, resources, and price structure.

CONTENTS

INTRODUCTION

Projections of the prices that the Navy will have to pay for different energy forms during the next 45 years have been made. Included are price projections for coal, natural gas, fuel oil and electricity.

These price estimates are based on a survey of available literature, and an estimate of technologies that may be available in the future to change energy demand, form, and availability. In a number of instances it was felt that biases were inherent in much of the literature. These were factored out of the estimates where possible.

The study started with a survey of available literature. In addition, a form letter was sent to over 100 government agencies, industry associations, and selected corporations asking for data and/or assistance in locating data. Replies have been received from approximately 45 of the addressees of the letter. Several additional responses were received by telephone.

Appendix A contains a copy of the form letter that was sent, and Appendix B contains a list showing those receiving the letter and those responding to the letter.

The form letter was not very successful in obtaining data, but it did succeed in determining where much of the data could be obtained. Most of the responses to the letter suggested that one or more of several organizations could be of assistance in providing the data.

Based on the responses to the letter, a trip to the Washington, D.C. area was made to obtain additional information. Places contacted during this visit included the Department of the Interior, Air Transport Association of America, Interstate National Gas Association, U.S. Geological Survey, Energy Research and Development Administration, Resources for the Future, Americans for Energy Independence, American Public Power Association, Federal Energy Administration, National Petroleum Council, United Mine Workers, Council on Wage and Price Stability, American Petroleum Institute, American Gas Association, Center for Strategic and International Studies, Booz-Allen Applied Research in Bethesda, Maryland, and the Hoffman-Muntner Corporation.

Reports and other available information were obtained when possible at each place visited. In addition, some literature was ordered.

A large number of reports were ordered through the Naval Weapons Center Technical Library. Some have been received but many are still on order.

A later trip was made to Rand in Santa Monica, Stanford Research Institute in Menlo Park, the Electric Power Research Institute in Palo

Alto, and the Geological Survey office in Menlo Park. Interesting discussions were held at the Stanford Research Institute and Rand on their energy studies and, in particular, on their energy computer models. It appears that a major objective of each model is to predict energy prices for the future.

A list of places visited and their addresses is included in Appendix C.

It appears that the study of the various aspects of energy cost and availability is very competitive. Copies of many of the studies are not generally available unless the corporate authors are contractually obligated to provide them.

The reluctance on the part of some to provide material probably is based on maintaining their competitive position, however, in a number of instances the studies are funded by private industry. This type of study probably should not be generally available.

The available literature has been published at various times and with different assumptions for inflation and base years. It was decided to use 1975 as the base year in this study and to correct all price data to 1975 dollars. This was done for both historical and future costs.

Past price data were corrected for inflation by using the Consumer Price Index (CPI) as shown in Appendix D. Consideration was also given to using the broader Gross National Product Implicit Deflator Index. Comparison of the results indicated it made very little difference.

The study then proceeded to make an estimate of the future energy consumption of the U.S. and how these requirements would be met. This was done by identifying the maximum and minimum values for the quantity of energy that could reasonably be expected to be consumed, and then making a most probable demand projection from considerations of past consumption.

The next section of this report covers the projection of the future energy consumption by the U.S. It is followed by a presentation of the basic assumptions that were made concerning future events. These assumptions include estimates of what will happen from political as well as technical standpoints. The number of assumptions that had to be made was kept as low as possible consistent with forming a firm base for the price projections.

The remaining sections of the report then combine these assumptions on future events and predicted consumption with estimates of available energy supplies as well as other considerations and predict future energy prices.

Appendix E contains some of the common fuel and power conversion factors. They were primarily taken from Ref. 1 and are included for the convenience of those reading this report.

FUTURE ENERGY REQUIREMENTS OF THE UNITED STATES

In order to estimate future energy prices with any degree of confidence, it is necessary to first estimate energy consumption for the time period of concern. It is necessary to estimate not only the net energy consumed but also gross energy used. This makes it necessary to estimate the form of the energy when consumed. For example, if the energy is in the form of electricity when used, it means that about three times that amount was actually used in making the electricity. In the case of electricity, energy prices are obviously not as important to the user as are other considerations such as pollution or convenience.

Probably the most reasonable estimate of the maximum energy to be consumed in the future can be calculated by assuming that the U.S. economy, on a gross national product (GNP) basis, will grow at the rate of 4.5% per year. This is representative of slightly more than a full employment economy with energy consumption following historical growth patterns.

The lowest reasonable estimate of future energy consumption results from a zero energy growth scenario. A zero energy growth scenario assumes that a philosophy of durability, not disposability, of goods is adopted.

For purposes of this study, a modified historical growth scenario is assumed in order to calculate the probable energy consumption for the period of interest. This scenario results in predictions of future energy consumption between the two extremes described above.

The historical growth scenario is best described by Ref. 2 as follows:

''The historical growth scenario requires a few basic policy decisions in the near future which would then be followed by some detailed implementation plans.

''(1) The government would have to emphasize expanded energy supplies in its actions rather than stressing active measures to promote conservation. Continued subsidies to limit increases in the price of energy may be needed. Demand would also be stimulated by a continuation of economic growth along current patterns. Policies generally favoring energy-intensive industries might be needed while government funding for mass transit or new housing construction to save energy would receive a lower priority.

''(2) The nation would have to develop all the major sources of energy growth-oil imports, outer continental shelf oil and gas, Rocky Mountain shale and coal, and nuclear power-in the near and medium term. Even so, it is possible to forego vigorous development of one of the options over the longer term if the others are pushed more aggressively. For example, under this scenario, a reduction in imports leading to self-sufficiency in the late 1980s is possible. Or, development of one of the following could be slowed but not eliminated: oil and gas development on the Atlantic and Pacific outer continental shelf, Rocky Mountain fossil fuel production or nuclear power. To do so would require pushing the other three options very hard.

''(3) Exploration and development of oil and gas would have to be encouraged by favorable government price, tax, and federal leasing policies. To get the large quantities required in the domestic oil and gas supply case, it would be essential to rapidly develop the Atlantic and Pacific outer continental shelves, Alaska, the Gulf of Mexico, and the Alaskan outer continental shelf. Development of western oil shale would have to be pushed as well. This raises federal leasing problems and environmental and regional development problems. Greater reliance on imported oil could ease some of these pressures, but it would require the construction of superports and would subject the coastal waters to oil spills and coastal industrialization similar to that which would accompany outer continental shelf production.

''(4) Increased coal use requires resolution of the strip mining and air pollution problems as well as labor and economic problems. With the anticipated prices for oil and gas, coal should have no problem competing with them on an economic basis, but the environmental question would have to be resolved.

''(5) Significant growth in nuclear power is required in this scenario. A 12-15 times increase in on-line nuclear capacity between now and 1985 is projected, based on the large number of plants now on order or under construction. It would be followed by an additional three- to four-fold increase by the year 2000, depending on the degree to which transportation is switched to electric power and the extent to which coal could be used to fuel electric power growth. Thus, questions of nuclear power safety, safeguarding nuclear materials and handling radioactive wastes would have to be resolved. To achieve the necessary rate of energy supply growth would require that design, siting, and federal licensing procedures for individual power plants be streamlined and standardized and that other elements in the nuclear power fuel cycle, such as enrichment, reprocessing and waste handling, proceed apace.

''(6) All of the supply options for this scenario require extremely large investments in refineries, power plants, pipelines, transmission lines and other large facilities. The capital requirements are large in comparison with other investments made by the economy, and may need to grow. Serious siting, technical manpower, and construction labor problems also arise in addition to the capital problem. Unless speedy solutions are found to this broad class of problems, the scenario would not be achieved.

''(7) Research and development programs which concentrate on enhancing energy supply and conversion technology and on environmental cleanup are crucial to the 'historical growth' scenario. The effort would emphasize medium-term technologies rather than fundamentally new, long-term technologies.''

The zero growth scenario would require a major modification in the way the United States has been proceeding in the past. It would require major modifications to past practices of product design and maintenance. It is generally agreed that the zero energy growth scenario will not be adopted over a short period of time. It is felt, however, that a gradual shift in that direction will occur. It is important to point out that zero energy growth does not require a zero economic growth situation.

The predicted gradual shift in the direction of zero energy growth leads to an assumption of a modified historical energy growth scenario. The modified historical energy growth scenario assumes that the United States economy will grow at a rate somewhat lower in the future than during the recent past.

This lower energy growth rate is expected to be a result of increasing energy prices as well as changes in government policies. The higher prices paid for energy are expected to gradually bring about a greater emphasis on durability of products and a recycling of materials. It is anticipated that laws will increasingly be enacted to enhance this.

Figure 1 (from Ref. 3) indicates that there is a very positive relationship between energy consumption per person and the respective standard of living of people in selected countries. Just how efficient the United States has been in its use of energy since 1920 is shown in Figure 2 (from Ref. 3). As a monetary measurement, gross national product (GNP) generated per unit of energy consumed indicates some fluctuations since 1920 but has exhibited a general growth path with upper and lower boundaries fairly well defined. Points outside these bounds (1942-1945) are associated with the increased productivity efforts of World War II. Based on this trend, a 1-2% continuing growth rate in energy efficiency is indicated. However, large improvements in energy technology or concerted efforts directed toward conservation could augment this growth rate. The increasing use of electricity will act to counter any increases in energy efficiency caused by energy conservation measures.

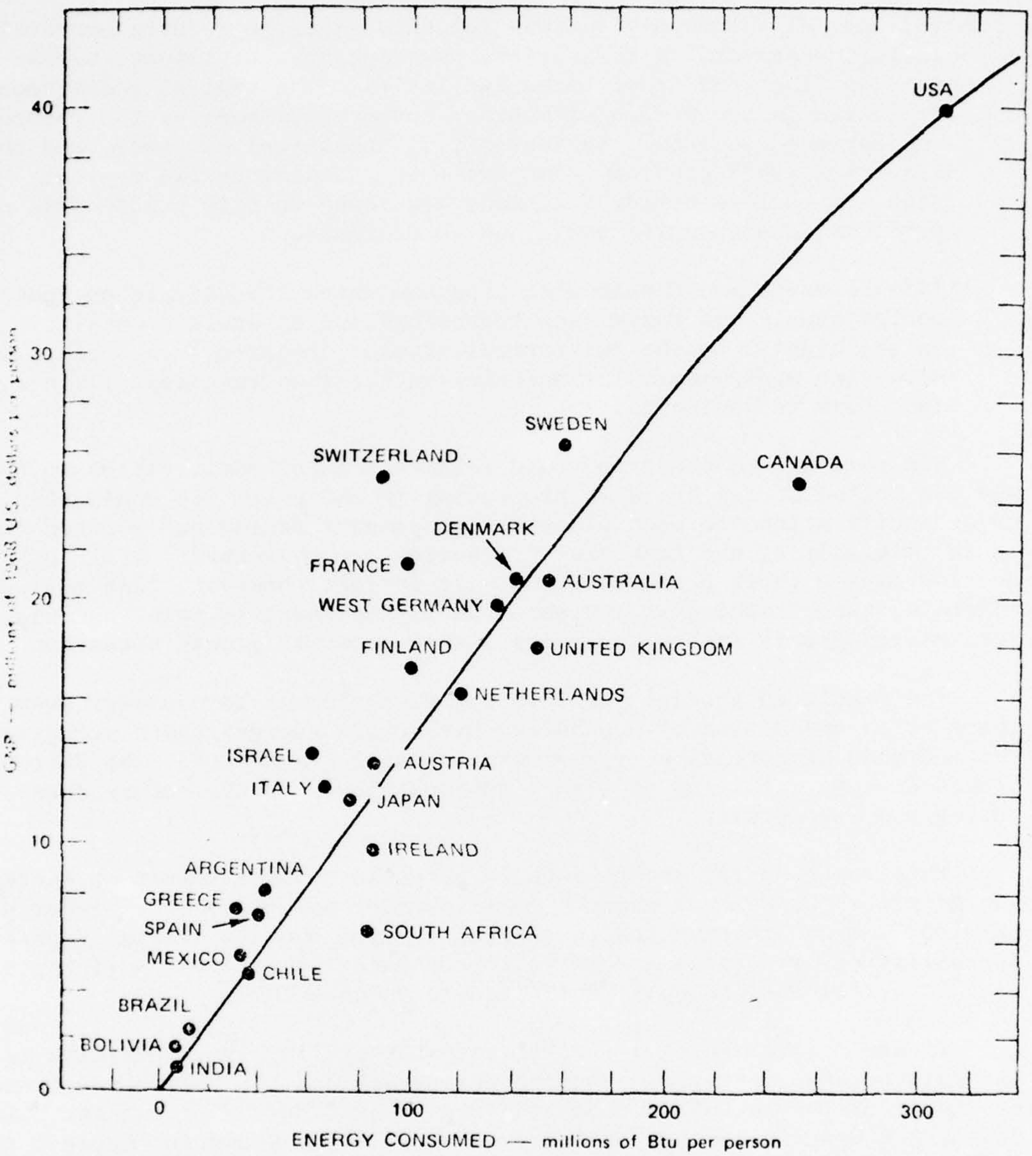


FIGURE 1. Relationship of GNP to Total Energy Consumed for Selected Countries, 1968 (Per Capita Basis).

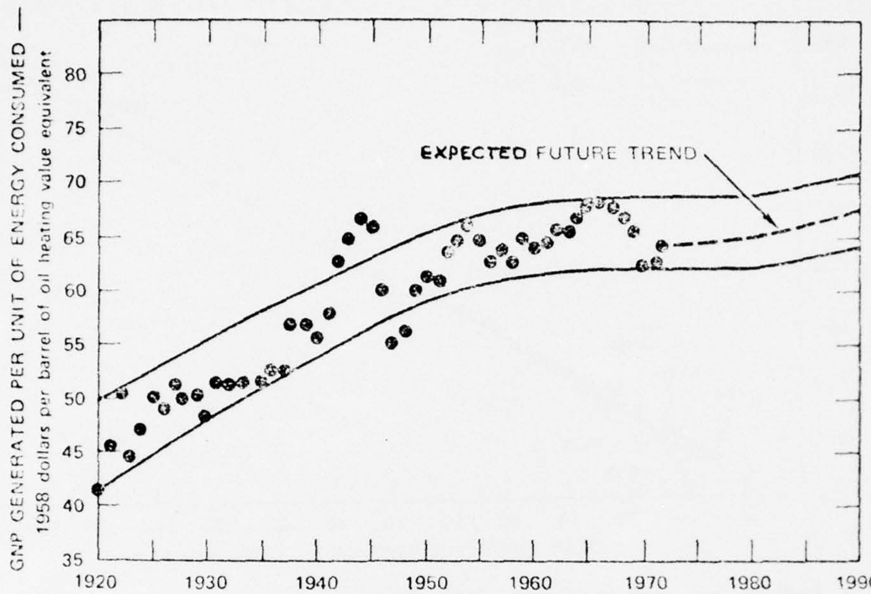


FIGURE 2. U.S. Energy Efficiency, 1920-1990.

Figure 3 (from Ref. 3) shows the relationship between GNP and total energy consumed in the United States over the period 1920-1972. It is highly correlated and linear in nature. It is to be expected that real increases in GNP will require and be associated with higher amounts of energy consumed.

Figure 4 indicates the gross national product that would result from different growth rates in the future. The heavy line in the figure indicates the postulated growth (3.5%) in GNP with time. It is the growth rate that is used to calculate the probable energy demand as shown in Figure 5. Both of these figures assume that no exogenous disturbances, such as wars, occur.

In Figure 5 the 3.5% growth curve represents the energy expected to be consumed for the year shown. Also shown in the figure are the reasonable extremes of total energy demand. Using the predicted energy requirements for the time period of interest, and the predicted availability and cost of the various types of energy as well as other considerations, Figure 6 was then prepared. It indicates the portion of the required total energy that each form of energy is expected to supply. This breakout is somewhat arbitrary but it is necessary to estimate demand for the various energy forms in order to estimate future costs.

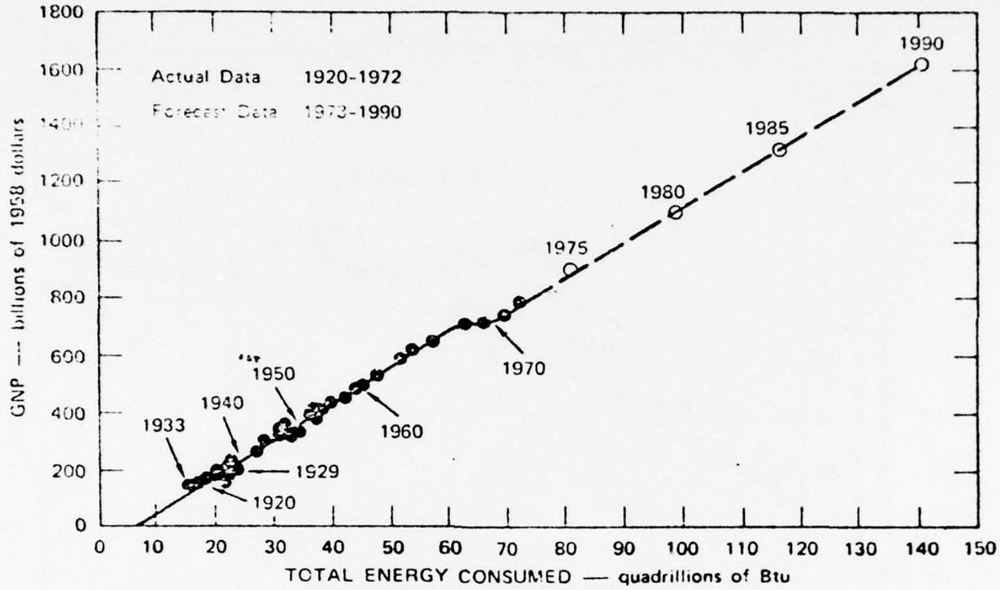


FIGURE 3. Relationship of GNP to Total Energy Consumed in the United States, 1920-1990.

FIGURE 4. GNP Versus Year and Growth Rate.

FIGURE 5. Energy Required Versus Year and Growth Rate.

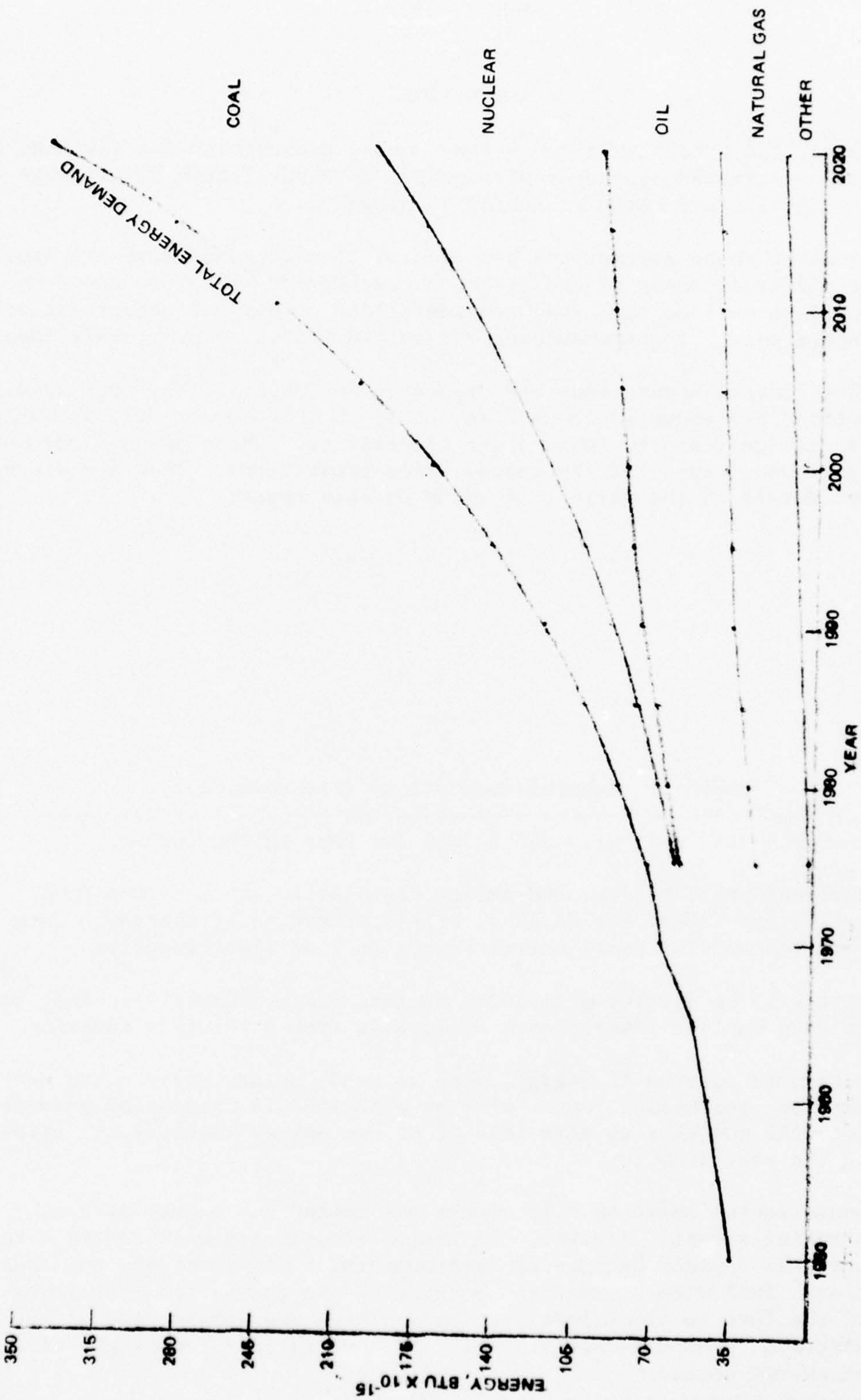


FIGURE 6. Predicted Consumption of Various Fuels.

ASSUMPTIONS

After the probable United States energy consumption for the next 45 years was estimated, a number of assumptions about future events were made. They are presented in Tables 1 through 5.

Some of these assumptions are general in nature and some are specific to the different types of energy being considered. They are based on political as well as technical considerations. They are consistent with the future energy requirements of the United States as previously identified.

The general assumptions are presented in Table 1. The more specific assumptions are shown in Table 2 for coal, in Table 3 for oil, in Table 4 for natural gas, and in Table 5 for electricity. These assumptions were then used as a basis for the energy price projections. They are discussed in some detail in the various sections of this report.

TABLE 1. General Assumptions (Probable Case).

1. Energy demand will grow about 3.5% per year in the future.

2. Environmental, health, and safety legislation, such as the Coal Health and Safety Act of 1969, will continue to be enacted. This legislation will cause energy prices to rise significantly.

3. Ways will be developed to solve nuclear waste disposal problems and to make nuclear power plants acceptable from a safety standpoint.

4. Alternate sources of energy, such as wind, solar, solid waste conversion, geothermal, etc., will be exploited in increasing amounts but will not make up more than 5% of our energy requirements prior to the year 2020.

5. Conservation measures will reduce the demand for energy by a substantial amount. However, the use of electricity will continue to increase rapidly because of environmental considerations, and additional fuel will be required because of the conversion efficiency of the fuel to electricity process. These two considerations are expected to approximately nullify each other so far as their effect on energy demand.

TABLE 2. Assumptions for Coal (Probable Case).

1. Technology will be developed to permit use of high sulphur coal in power generation with an ''acceptable'' level of pollution.

2. Strip mining of western coal will be permitted with land reclamation.

3. Synthetic pipeline gas will be made from coal in significant quantities after 1985.

4. Synthetic liquid fuels will be produced from coal in significant quantities after 1990.

5. Real earnings of coal miners will increase at 1-3% per year faster than the average for all wage earners.

TABLE 3. Assumptions for Natural Gas (Probable Case).

1. There will be a partial decontrol of prices.

2. There will be end-use control.

3. Liquid natural gas will be imported in quantity after 1980.

4. Significant quantities of Alaskan natural gas will be imported after 1985.

5. Synthetic pipeline gas will be made from coal in significant quantities after 1985.

TABLE 4. Assumptions for Oil (Probable Case).

1. Political, economic and logistical considerations will not greatly restrict the availability of foreign oil or gas in the long term.

2. Extraction of shale oil will reach significant production levels after 1990.

3. Synthetic oil will be produced in significant quantities after 1990.

TABLE 5. Assumptions for Electricity (Probable Case).

1. Pollution considerations will require the consumption of electricity to continue to rise at a high rate.

2. Nuclear energy will be used to power electric plants at a rapidly increasing rate.

3. Most power plants will be fueled by coal.

4. The use of oil and natural gas for power plants will be severely limited by legislation.

COAL

INTRODUCTION

The United States has abundant resources of coal. In the face of a widening energy gap, our domestic coal resources potentially represent an asset of significant value. A major question, however, is the extent to which the United States can capitalize on this asset. The production of coal must be expanded and additional uses of coal must be developed which are environmentally acceptable and economically sound in order for us to exploit this asset.

It is clear that the United States coal resources can make a major contribution to the nation's future energy needs only with the further development and application of technologies for:

1. Solving the environmental problems inherent in the mining and combustion of coal.
2. Transforming solid coal into synthetic gaseous and liquid fuels.
3. Transporting and storing coal economically.

COAL RESOURCES OF THE UNITED STATES

The United States has vast resources of coal. The United States Geological Survey (USGS) has identified deposits at depths of less than 3,000 feet containing about 1,600 billion tons. They estimate that additional coal resources of similar size exist on the basis of broad geological knowledge and theory.

Table 6 (from Ref. 4) shows the estimated remaining coal resources of the United States as of January 1, 1974. These estimates include beds of bituminous and anthracite generally 14 inches or more thick, and beds of subbituminous coal and lignite 2 1/2 feet or more thick, to overburden depths of 3,000 and 6,000 feet.

Coal reserves generally reported by the USGS are divided into three categories according to the relative abundance and reliability of data used in preparing the estimates. These classes are termed ''measured'', ''indicated'' and ''inferred''. Measured reserves are those for which tonnage is computed and dimensions revealed in outcrops, trenches, mine workings and drill holes. The points of observation and measurement are so closely spaced and the thickness and extent of coal are so well defined that the tonnage is judged to be accurate within 20% of true tonnage. Although the spacing of the points of observation necessary to demonstrate continuity of the coal differs from region to region according to the character of the coal beds, the points of observation are, in general, about 0.5 mile apart.

Indicated resources are those for which tonnage is computed partly from specific measurements and partly from projections of visible data for a reasonable distance on the basis of geological evidence. In general, the points of observation are about 1.0 mile apart, but they may be as much as 1.5 miles apart for beds of known continuity.

The sizing categories selected to classify the bed thickness of the reserves in the estimates presented here are limited to those that conform closely to present mining practices. Specifically, for higher rank coals (bituminous, semi-anthracite and anthracite), reserves are classified into two bed thicknesses, namely 28 to 42 inches and more than 42 inches. For lower rank coals (subbituminous and lignite), bed thicknesses are limited to 5 to 10 feet thick.

Table 7 (from Ref. 5) shows a tabulation by states of the measured and indicated coal reserve in beds 28 inches and more in thickness under a maximum overburden thickness of 1,000 feet. Comparison is made of these specific conditions with coal resources in the ground having a bed thickness of 14 inches or more and under a maximum overburden thickness of 3,000 feet.

Tables 8, 9, and 10 (from Ref. 5) show by individual states the estimated remaining measured and indicated reserves as of January 1, 1970, in various bed thicknesses with maximum overburden of less than 1,000 feet. Reference 5 states, ''These data were derived by using the various reports listed in USGS bulletins 1136 and 1275 and various Bureau of Mines reports. All production data were derived from the Bureau of Mines reports. Losses in mining were assumed to have been equal to production, and production plus losses in mining have in all cases have been subtracted from measured reserves.''

TABLE 6. Total Estimated Remaining Coal Resources of the United States, January 1, 1974.

[In millions (10^6) of short tons. Estimates include beds of bituminous coal and anthracite generally 14 in. or more thick, and beds of subbituminous coal and lignite generally 2½ ft or more thick, to overburden depths of 3,000 and 6,000 ft. Figures are for resources in the ground]

State	Overburden 0-3,000 feet: Remaining identified resources, Jan. 1, 1974 (from table 2): Bituminous coal	Subbituminous coal	Lignite	Anthracite and semianthracite	Total	Estimated hypothetical resources in unmapped and unexplored areas[1]	Estimated total identified and hypothetical resources remaining in the ground	Overburden 3,000-6,000 feet: Estimated additional hypothetical resources in deeper structural basins[1]	Overburden 0-6,000 feet: Estimated total identified and hypothetical resources remaining in the ground
Alabama	13,262	0	2,000	0	15,262	20,000	35,262	6,000	41,262
Alaska	19,413	110,666	(2)	(3)	130,079	130,000	260,079	5,000	265,079
Arizona	[4]21,234	(4)	0	0	21,234	0	21,234	0	21,234
Arkansas	1,638	0	350	428	2,416	[5]4,000	6,416	0	6,416
Colorado	109,117	19,733	20	78	128,948	161,272	290,220	143,991	434,211
Georgia	24	0	0	0	24	60	84	0	84
Illinois	146,001	0	0	0	146,001	100,000	246,001	0	246,001
Indiana	32,868	0	0	0	32,868	22,000	54,868	0	54,868
Iowa	6,505	0	0	0	6,505	14,000	20,505	0	20,505
Kansas	18,668	0	(6)	0	18,668	4,000	22,668	0	22,668
Kentucky:									
Eastern	28,226	0	0	0	28,226	24,000	52,226	0	52,226
Western	36,120	0	0	0	36,120	28,000	64,120	0	64,120
Maryland	1,152	0	0	0	1,152	400	1,552	0	1,552
Michigan	205	0	0	0	205	500	705	0	705
Missouri	31,184	0	0	0	31,184	17,489	48,673	0	48,673
Montana	2,299	176,819	112,521	0	291,639	180,000	471,639	0	471,639
New Mexico	10,748	50,639	0	4	61,391	[7]65,556	126,947	74,000	200,947
North Carolina	110	0	0	0	110	20	130	5	135
North Dakota	0	0	350,602	0	350,602	180,000	530,602	0	530,602
Ohio	41,166	0	0	0	41,166	6,152	47,318	0	47,318
Oklahoma	7,117	0	(6)	0	7,117	15,000	22,117	[9]5,000	27,117
Oregon	50	284	0	0	334	100	434	0	434
Pennsylvania	63,940	0	0	18,812	82,752	[8]4,000	86,752	[10]3,600	90,352
South Dakota	0	0	2,185	0	2,185	1,000	3,185	0	3,185
Tennessee	2,530	0	0	0	2,530	2,000	4,530	0	4,530
Texas	6,048	0	10,293	0	16,341	[11]112,100	128,441	(11)	128,441
Utah	[12]23,186	173	0	0	23,359	[13]22,000	45,359	35,000	80,359
Virginia	9,216	0	0	335	9,551	5,000	14,551	100	14,651
Washington	1,867	4,180	117	5	6,169	30,000	36,169	15,000	51,169
West Virginia	100,150	0	0	0	100,150	0	100,150	0	100,150
Wyoming	12,703	123,240	(2)	0	135,943	700,000	835,943	100,000	935,943
Other States[14]	610	[15]32	[16]46	0	688	1,000	1,688	0	1,688
Total	747,357	485,766	478,134	19,662	1,730,919	1,849,649	3,580,568	387,696	3,968,264

[1]Source of estimates: Alabama, W. C. Culbertson; Arkansas, B. R. Haley; Colorado, Holt (1975); Illinois, M. E. Hopkins and J. A. Simon; Indiana, C. E. Wier; Iowa, E. R. Landis; Kentucky, K. J. Englund; Missouri, Robertson (1971, 1973); Montana, R. E. Matson; New Mexico, Fassett and Hinds (1971); North Dakota, R. A. Brant; Ohio, H. R. Collins and D. O. Johnson from data in Struble and others (1971); Oklahoma, S. A. Friedman; Oregon, R. S. Mason; Pennsylvania anthracite, Arndt and others (1968); Pennsylvania bituminous coal, W. E. Edmunds; Tennessee, E. T. Luther; Texas lignite, Kaiser (1974); Virginia, K. J. Englund; Utah, H. H. Doelling; Washington, H. M. Beikman; Wyoming, N. M. Denson, G. B. Glass, W. R. Keefer, and E. M. Schell; remaining States, by *the author*.

[2]Small resources of lignite included under subbituminous coal.

[3]Small resources of anthracite in the Bering River field believed to be too badly crushed and faulted to be economically recoverable (Barnes, 1951).

[4]All tonnage is in the Black Mesa field. Some coal in the Dakota Formation is near the rank boundary between bituminous and subbituminous coal. Does not include small resources of thin and impure coal in the Deer Creek and Pinedale fields.

[5]Lignite.

[6]Small resources of lignite in western Kansas and western Oklahoma in beds generally less than 30 in. thick.

[7]After Fassett and Hinds (1971), who reported 85,222 million tons "inferred by zone" to an overburden depth of 3,000 ft in the Fruitland Formation of the San Juan basin. Their figure has been reduced by 19,666 million tons as reported by Read and others (1950) for coal in all categories also to an overburden depth of 3,000 ft in the Fruitland Formation of the San Juan basin. The figure of Read and others was based on measured surface sections and is included in the identified tonnage recorded in table 2.

[8]Includes 100 million tons inferred below 3,000 ft.

[9]Bituminous coal.

[10]Anthracite.

[11]Lignite, overburden 200-5,000 ft; identified and hypothetical resources undifferentiated. All beds assumed to be 2 ft thick, although many are thicker.

[12]Excludes coal in beds less than 4 ft thick.

[13]Includes coal in beds 14 in. or more thick, of which 15,000 million tons is in beds 4 ft or more thick.

[14]California, Idaho, Nebraska, and Nevada.

[15]California and Idaho.

[16]California, Idaho, Louisiana, and Mississippi.

TABLE 7. Total Estimated Remaining Measured and Indicated Coal Reserves of the United States as of January 1, 1970.*

(In Beds 28 Inches and More Thick, for Bituminous, Anthracite and Semi-Anthracite, and 5 Feet or More Thick for Subbituminous and Lignite Beds--Million Tons)

State	Remaining Measured and Indicated Reserves: Bituminous	Subbituminous	Lignite	Anthracite Semi-Anthracite	Total	Total--All Ranks More than 14" and 3,000' Overburden	Measured & Indicated as Percent of Total
Alabama	1,731	0	†	0	1,731	13,444	12.9
Alaska	667	5,345	‡	§	6,012	130,087	4.6
Arkansas	313	0	†	67	380	2,420	15.7
Colorado	8,811	4,453	0	16	13,280	80,679	16.5
Georgia	18	0	0	0	18	18	100.0
Illinois	60,007	0	0	0	60,007	139,372	43.1
Indiana	11,177	0	0	0	11,177	34,661	32.2
Iowa	2,159	0	0	0	2,159	6,513	33.1
Kansas	328	0	0	0	328	18,678	1.8
Kentucky West	20,876	0	0	0	20,876	36,482	57.2
Kentucky East	11,049	0	0	0	11,049	28,550	38.3
Maryland	557	0	0	0	557	1,168	47.7
Michigan	125	0	0	0	125	220	56.8
Missouri	12,623	0	0	0	12,623	23,339	54.1
Montana	862	31,228	6,378	0	38,468	221,698	17.6
New Mexico	1,339	779	0	2	2,120	61,455	3.4
North Carolina	†	0	0	0	†	110	0.0
North Dakota	0	0	36,230	0	36,230	350,649	10.3
Ohio	17,242	0	0	0	17,242	41,568	41.5
Oklahoma	1,583	0	0	0	1,583	3,195	49.5
Oregon	**	**	0	0	**	[illegible]	0.0
Pennsylvania	24,078	0	0	12,525	36,603	69,698	52.5
South Dakota	0	0	757	0	757	2,031	37.3
Tennessee	939	0	0	0	939	2,608	36.0
Texas	**	0	6,870	0	6,870	12,918	53.2
Utah	9,155	150	0	0	9,305	32,070	29.0
Virginia	3,561	0	0	125	3,686	9,817	37.3
Washington	312	1,188	0	0	1,500	6,183	24.3
West Virginia	68,023	0	0	0	68,023	101,186	67.3
Wyoming	3,975	25,937	‡	0	29,912	120,581	24.8
Other States	**	**	45	0	45	4,[illegible]	1.0
Total	261,510	69,080	50,781	12,735	394,106	1,556,840	25.3

* Figures are reserves in ground, about half of which may be considered recoverable. Includes all beds under less than 1,000 feet of overburden and over 28 inches in bed thickness for bituminous and anthracite and 5 feet or more for subbituminous and lignite.

† Small reserves of lignite in beds less than 5 feet thick.

‡ Small reserves of lignite included with subbituminous reserves.

§ Small reserves of anthracite in the Bering River Field believed to be too badly crushed and folded to be economically recoverable.

\# Negligible reserves with overburden less than 1,000 feet.

** Data not available to make estimate.

TABLE 8. Summary of Estimated Original or Remaining Reserves of Bituminous Coal of the United States According to Thickness of Beds and Under Less Than 1,000 Feet of Overburden.*

(Million tons)

State	Type of Estimate†	Estimated Original or Remaining Resources	Resources Depleted to 1-1-70: Production‡	Resources Depleted to 1-1-70: Production Plus Loss in Mining§	Remaining Resources 1-1-70	Remaining Reserves in Measured and Indicated Categories Under Maximum Overburden Thickness of 1,000 Feet According to Bed Thickness: 28"-42"	Over 42"	Total Over 28"
Alabama	R-1958	13,754	165	330	13,424	1,035	696	1,731
Alaska	Orig.	19,429	7	14	19,415	238	429	667
Arkansas	Orig.	1,816	81	162	1,654	153	160	313
Colorado	Orig.	63,203	417	834	62,369	1,435	7,376	8,811
Georgia	R-1945	24	3	6	18	18	-	18
Illinois	R-1965	140,000	314	628	139,372	8,667	51,340	60,007
Indiana	Orig.	37,293	1,316	2,632	34,661	2,576	8,601	11,177
Iowa	Orig.	7,237	362	724	6,513	1,037	1,122	2,159
Kansas	R-1957	18,706	14	28	18,678	Neg.	328	328
Kentucky West	Orig.	38,878	1,198	2,396	36,482	445	20,431	20,876
Kentucky East	Orig.	33,440	2,295	4,590	28,850	7,395	3,654	11,049
Maryland	R-1950	1,200	16	32	1,168	369	188	557
Michigan	Orig.	297	46	92	205	110	15	125
Missouri	Orig.	23,977	319	638	23,339	9,448	3,175	12,623
Montana	Orig.	2,363	88	176	2,187	192	670	862
New Mexico	Orig.	10,948	94	188	10,760	486	853	1,339
North Carolina	Orig.	112	1	2	110	‖	‖	‖
Ohio	Orig.	46,488	2,460	4,920	41,568	14,202	3,040	17,242
Oklahoma	Orig.	3,673	188	376	3,297	800	783	1,583
Oregon	Orig.	50	1	2	48	**	**	**
Pennsylvania	Orig.	75,093	8,966	17,932	57,161	9,382	14,691	24,073
Tennessee	R-1959	2,748	71	142	2,606	713	226	939
Texas	Orig.	6,100	26	52	6,048	††	††	††
Utah	Orig.	32,522	301	602	31,920	4,878	4,277	9,155
Virginia	Orig.	11,696	1,111	2,222	9,474	2,489	1,072	3,561
Washington	R-1960	1,869	1	2	1,867	62	250	312
West Virginia	Orig.	116,618	7,716	15,432	101,186	20,036	47,987	68,023
Wyoming	Orig.	13,235	275	550	12,685	831	3,144	3,975
Other States‡‡		620	1	2	618	**	**	**
Total		723,380	27,853	55,706	667,683	86,997	174,513	261,510

* USGS Bulletins 1136 and 1275, with adjustments for production and losses in mining through 1969.

† R--remaining resources in ground as of January 1 of the year indicated; original resources in the ground before the advent of mining.

‡ Production from year of earliest record or from year that remaining resources were estimated through 1969.

§ Past losses assumed to equal production.

‖ Negligible reserves with overburden less than 1,000 feet.

** Data not available to make estimates.

†† Negligible reserves in measured and indicated categories.

‡‡ Arizona, California, Idaho, Nebraska and Nevada.

TABLE 9. Summary of Estimated Original or Remaining Reserves of Subbituminous Coal and Lignite of the United States According to Thickness of Beds and With Less Than 1,000 Feet of Overburden.*

(Million Tons)

State	Type of Estimate†	Estimated Original or Remaining Resources	Resources Depleted to 1-1-70: Production‡	Resources Depleted to 1-1-70: Production Plus Loss in Mining§	Remaining Resources 1-1-70	Remaining Reserves in Measured and Indicated Categories Under Maximum Overburden Thickness of 1,000 Feet According to Bed Thickness: 5'-10'	Over 10'	Total Over 5'
Subbituminous								
Alaska	Orig.	110,696	12	24	110,672	757	4,588	5,345
Colorado	Orig.	18,492	130	260	18,232	2,346	2,107	4,433
Montana	Orig.	132,151	82	164	131,987	11,615	19,613	31,228
New Mexico	Orig.	50,801	55	110	50,691	576	203	779
Oregon	Orig.	290	3	6	284	#	#	#
Utah	Orig.	156	3	6	150	0	150	150
Washington	R-1960	4,194	Neg.	Neg.	4,194	822	366	1,188
Wyoming	Orig.	168,319	160	320	167,999	9,222	16,715	25,937
Other States	Orig.	4,065	4	8	4,057	#	#	#
Total		429,164	449	898	428,266	25,338	43,742	69,060
Lignite								
Alabama	Orig.	20	0	0	20	0	0	0
Alaska	Orig.	**	0	0	**	0	0	**
Arkansas	Orig.	350	0	0	350	0	0	0
Kansas	Orig.	††	0	0	††	0	0	††
Montana	Orig.	87,533	3	6	87,527	4,960	1,918	6,878
North Dakota	Orig.	350,910	130	260	350,650	27,591	13,639	35,230
Oklahoma	Orig.	††	0	0	††	0	0	††
South Dakota	Orig.	2,033	1	2	2,031	705	52	757
Texas	Orig.	7,070	100	200	6,870	6,870	0	6,870
Washington	R-1960	117	0	0	117	0	0	0
Wyoming	Orig.	**	0	0	**	0	0	**
Other States	Orig.	50	2	4	46	46	0	46
Total		448,083	236	472	447,611	35,172	15,609	50,781
Grand Total		877,247	685	1,370	875,877	60,510	59,351	119,861

* USGS Bulletins 1136 and 1275, with adjustments for production and losses in mining through 1969.

† R--remaining resources in the ground as of January 1 of the year indicated; original resources in the ground before the advent of mining.

‡ Production from years earliest record or from year that remaining reserves were estimated through 1969.

§ Past losses assumed to equal production.

\# Classification of reserve data not available.

** Small resources and production of lignite included under subbituminous coal.

†† Small resources of lignite in beds generally less than 30 inches thick.

TABLE 10. **Summary of Estimated Original or Remaining Reserves of Anthracite and Semi-Anthracite Coal Reserves of the United States According to Thickness of Beds and With Less Than 1,000 Feet of Overburden.***

(Million Tons)

State	Type of Estimate†	Estimated Original or Remaining Resources	Production‡	Production Plus Loss in Mining§	Remaining Resources 1-1-70	Remaining Reserves in Measured and Indicated Categories Under Maximum Overburden Thickness of 1,000 Feet According to Bed Thickness: 28"-42"	Over 42"	Total
Alaska	-	‖	0	0	0	0	0	0
Arkansas	Orig.	456	20	40	416	54	13	67
Colorado	Orig.	90	6	12	78	6	10	16
New Mexico	Orig.	6	1	2	4	1	1	2
Pennsylvania	Orig.	22,805	5,140**	10,280	12,525	††	††	12,525
Virginia	Orig.	355	6	12	343	11	114	125
Washington	R-1960	5	Neg.	Neg.	5	‡‡	‡‡	‡‡
Total		23,717	5,173	10,346	13,371	72	138	12,735

* USGS Bulletins 1136 and 1275, with adjustments for production and losses in mining through 1969.

† R--remaining reserves in the ground as of January 1 of the year indicated; original resources in the ground before the advent of mining.

‡ Production from year of earliest record or from year that remaining reserves were estimated through 1969.

§ Past losses assumed to equal production.

‖ Small resources of anthracite in the Bearing River Field believed to be too badly crushed and faulted to be economically recoverable.

** Excludes anthracite recovered from culm banks and dredging.

†† Classification of reserves according to bed thickness is not available.

‡‡ Small reserves are in the inferred category.

Table 11 (from Ref. 5), which is a compilation of the remaining reserves of medium and low volatile bituminous coals, gives some indication of the reserves of these coals which are used largely for special purposes (coking) in the United States and abroad and may not be available for heat and power generation use. As shown in Table 11, these special purpose coals represent less than one-fifth of the measured and indicated reserves of bituminous coal in those states where they are found.

Tables 12 and 13 (from Ref. 5) contain statistics on strippable coal reserves in the United States. These tables show the minimum coal bed thickness, maximum overburden thickness and economic stripping ratio. Reference 5 states, ''The original in-place resource was obtained mainly in two ways:

> In published reports where outcrop maps were available, the length of each minable coal bed outcrop was measured by map meter or the area was measured by planimeter, and an average coal bed thickness was determined for each bed. An average bench width from outcrop to maximum overburden thickness was estimated. This data gave acres of strippable coal which, when multiplied by a tonnage factor, gave total original in-place resource.
>
> From latest estimates of the U.S. Geological Survey, State Geological Survey, coal mining companies and railroad companies.

''Remaining strippable reserves are total original coal resources reduced by depletion computed from past strip and auger production to date of estimate. Available strippable reserves are the recoverable reserves adjusted to conform to the economic stripping ratios assigned to the various states. Coal that cannot be mined owing to proximity of natural or man-made features is excluded from this estimate.''

The United States' coal reserves as indicated are so large that only about 10% of the remaining coal reserve could supply all the energy expected to be consumed by the United States between now and the year 2020.

COAL DEMAND

Table 14 (Ref. 6) shows United States coal production for the period 1890-1975. Also shown is the cumulative production during that period. The records for coal production prior to 1890 are not readily available, but production was small. Tables 6 and 14 indicate that the quantity of coal mined to date is equivalent to less than 10% of the estimated present day reserves.

TABLE 11. Summary of Measured and Indicated Reserves of Medium and Low Volatile Bituminous Coal in the United States According to Bed Thickness and Under Less Than 1,000 Feet Overburden.*

(Million Tons)

State	Remaining Reserves According to Thickness of Beds--1-1-70			Total Remaining Reserves--All Grades over 28"	Medium & Low Volatile as % of Total
	28"-42"	Over 42"	Total		
Alabama	420	380	800	1,731	46
Arkansas	153	160	313	313	100
Colorado	0	386	386	8,811	4
Maryland†	200	100	300	557	54
Oklahoma	273	274	547	1,583	35
Pennsylvania†	2,200	5,200	7,400	24,078	31
Tennessee†	60	160	220	939	24
Virginia	770	330	1,100	3,561	31
Washington	40	80	120	312	33
West Virginia†	2,730	6,370	9,100	68,023	13
Total	6,846	13,440	20,286	109,908	19

* Based on data published in USGS Bulletins 1136 and 1275 and various U.S. Bureau of Mines publications containing data on analysis of bituminous coal in individual states.

† Based in part on data published in U.S. Bureau of Mines Coking Coal Survey Reports (1948-1955--Dowd reports).

TABLE 12. Summary of Estimated Reserves of Strippable Bituminous Coal in the United States.*
(Million Short Tons)

Region and State	Remaining Strippable Reserves	Available Strippable Reserves	Minimum Coal Bed Thickness (Inches)	Maximum Overburden Thickness (Feet)	Economic Stripping Ratio (Feet:Feet)
Appalachia					
Alabama	607	134	14	120	24:1
Kentucky--East	4,609	781	28	120	14:1
Maryland	150	21	28	120	15:1
Ohio	5,566	1,033	28	120	15:1
Pennsylvania	2,272	752	28	120	15:1
Tennessee	483	74	28	120	19:1
Virginia	2,741	258	28	120	15:1
West Virginia	11,230	2,118	28	120	15:1
Subtotal	27,658	5,171			
Midwest					
Arkansas	200	149	14	60	30:1
Illinois	18,845	3,247	18	150	18:1
Indiana	2,741	1,096	14	90	20:1
Iowa	1,000	180	28	120	18:1
Kansas	1,388	375	12	120	15:1
Kentucky--West	4,746	977	24	150	18:1
Michigan	6	1	28	100	20:1
Missouri	3,425	1,160	12	120	15:1
Oklahoma	434	111	12	120	15:1
Subtotal	32,785	7,296			
Rocky Mountain & Pacific Coast					
Alaska†	1,201	480	14	120	10:1
Colorado	870	500	60	50 to 120	4:1-10:1
Utah	252	150	60	39 to 150	3:1-8:1
Subtotal	2,323	1,130			
Total‡	62,766	13,597			

* Based on recent Bureau of Mines study of strippable coal reserves of the United States.

† Includes 478 million tons of reserves in Northern Alaska Fields (North Slope) that may not be economically strippable at this time.

‡ Strippable bituminous coal reserves for Idaho, Montana, New Mexico, Texas and Washington were not estimated.

TABLE 13. **Summary of Estimated Reserves of Strippable Subbituminous and Lignite Coal in the United States.***

(Million Short Tons)

Region and State	Remaining Strippable Reserves	Available Strippable Reserves	Minimum Coal Bed Thickness (Inches)	Maximum Overburden Thickness (Feet)	Economic Stripping Ratio (Feet:Feet)
			Subbituminous†		
Rocky Mountain & Pacific Coast					
Alaska	6,190	3,926‡	60	120	12:1
Arizona	400	387	60	130	8:1
California	100	25	60	100	1:1
Montana	7,813	3,400	60	60 to 125	2:1-18:1
New Mexico	3,307	2,474	60	60 to 90	8:1-12:1
Washington	500	135	60	100	10:1
Wyoming	22,028	13,971	60	60 to 200	1.5:1-10:1
Total	40,338	24,318			
			Lignite†		
Southwest					
Arkansas	32	25	60	100	15:1
Texas	3,272	1,309	60	90	15:1
Subtotal	3,304	1,334			
Rocky Mountain & Pacific Coast					
Alaska	8	5	0	0	0
Montana	7,058	3,497	60	60 to 125	2:1-18:1
North Dakota	5,239	2,075	60	50 to 125	3:1-12:1
South Dakota	399	160	60	100	12:1
Subtotal	12,704	5,737			
Total	16,008	7,071			
Total all Ranks	119,112	44,986			

* Based on recent unpublished Bureau of Mines study of strippable coal reserves of the United States.

† Subbituminous coal reserves not estimated for Colorado and Oregon; lignite reserves not estimated for Alabama, Kansas, Louisiana and Mississippi.

‡ Includes 179 million tons of undifferentiated subbitumous-lignite and 3,387 million tons of subbituminous coal reserves in the Northern Alaska Fields (North Slope) that may not be economically strippable at this time.

TABLE 14. United States Coal Production from 1890 to Present.

Year	Production, thousand tons	Cumulative production, thousand tons
1890	111,302	111,302
1891	117,901	229,203
1892	126,857	356,060
1893	128,358	484,445
1894	118,820	603,265
1895	135,118	738,383
1896	137,640	876,023
1897	147,618	1,023,641
1898	166,594	1,190,235
1899	193,232	1,383,558
1900	212,316	1,595,874
1901	225,828	1,821,702
1902	260,217	2,081,919
1903	282,749	2,364,668
1904	278,660	2,643,328
1905	315,063	2,958,391
1906	342,879	3,301,266
1907	395,759	3,697,025
1908	332,574	4,029,599
1909	379,744	4,409,343
1910	417,111	4,826,454
1911	405,907	5,232,361
1912	450.105	5,232,361

TABLE 14. (Contd.)

Year	Production, thousand tons	Cumulative production, thousand tons
1913	478,435	6,160,901
1914	422,624	6,483,522
1915	442,624	6,583,525
1916	502,520	7,528,669
1917	551.791	8,080,460
1918	579,386	8,659,846
1919	465,860	9,125,706
1920	568,667	9,694,373
1921	415,922	10,110,295
1922	422,268	10,532,563
1923	564,565	11,097,128
1924	483,687	11,617,181
1925	520,053	12,137,234
1926	573,367	12,710,601
1927	517,763	13,228,364
1928	500,745	13,729,109
1929	534,989	14,264,098
1930	476,526	14,731,624
1931	382,089	15,113,713
1932	309,710	15,423,423
1933	333,631	15,757,054
1934	359,368	16,116,422
1935	372,373	16,488,795

TABLE 14. (Contd.)

Year	Production, thousand tons	Cumulative production, thousand tons
1936	439,088	16,927,833
1937	455,531	17,373,414
1938	348,545	17,721,959
1939	394,855	18,166,814
1940	400,722	18,517,586
1941	514,149	19.031,735
1942	582,693	19,614,428
1943	590,177	20,234,004
1944	619,576	20,853,580
1945	577,617	21,431,197
1946	533,922	21,956,119
1947	630,624	22,595,743
1948	599,518	23,195,261
1949	437,868	23,633,129
1950	516,311	24,149,440
1951	533,665	25,149,946
1952	466,841	25,149,946
1953	457,290	25,607,236
1954	391,706	25,998,942
1955	464,633	26,463,575
1956	500,874	26,964,449
1957	492,704	27,457,153

TABLE 14. (Contd.)

Year	Production, thousand tons	Cumulative production, thousand tons
1958	410,446	27,867,599
1959	412,028	28,279,627
1960	415,512	28,695,139
1961	402,977	29,098,116
1962	422,149	29,520,265
1963	458,928	29,979,193
1964	486,998	30,466,191
1965	512,088	30,978,279
1966	533,881	31,512,160
1967	522,654	32,064,814
1968	545,245	32,610,059
1969	560,505	32,666,109
1970	602,932	33,269,041
1971	553,192	33,821,233
1972	585,386	34,406,619
1973	591,738	34,998,357
1974	603,406	35,601,763
1975	640,000	36,241,763

Table 15 shows the volume of imports and exports during this same time period. It is readily seen that the volume of imports is negligible. The exports make up about 10% of total United States production. This value isn't expected to change very much in the future because of the cost of transporting coal.

TABLE 15. United States Coal Imports and Exports.

Year	Production, thousand tons		Year	Production, thousand tons	
	Exports	Imports		Exports	Imports
1890	1,272	1,047	1920	38,517	1,245
1891	1,652	1,182	1921	23,131	1,258
1892	1,905	1,497	1922	12,413	5,060
1893	1,986	1,714	1923	21,454	1,882
1894	2,440	1,246	1924	17,100	417
1895	2,660	1,411	1925	17,462	402
1896	2,516	1,893	1926	35,272	486
1897	2,670	1,443	1927	18,012	550
1898	3,004	1,426	1928	16,164	547
1899	3,898	1,410	1929	17,429	495
1900	6,061	1,912	1930	15,877	241
1901	6,455	2,215	1931	12,126	206
1902	6,049	2,174	1932	8,814	187
1903	5,806	4,044	1933	9,037	197
1904	7,207	2,180	1934	10,869	180
1905	7,513	1,203	1935	9,742	202
1906	8,014	2,039	1936	10,659	272
1907	9,470	1,493	1937	13,145	258
1908	11,071	2,219	1938	10,490	241
1909	10,101	1,375	1939	11,590	355
1910	11,663	1,820	1940	16,466	372
1911	13,260	1,973	1941	20,740	390
1912	16,475	1,456	1942	22,943	498
1913	18,013	1,768	1943	25,836	758
1914	17,590	1,521	1944	26,032	634
1915	18,777	1,704	1945	27,956	467
1916	21,255	1,714	1946	41,197	435
1917	23,840	1,468	1947	68,667	290
1918	22,351	1,457	1948	45,930	291
1919	20,114	1,012	1949	27,842	315

TABLE 15. (Contd.)

Year	Production, thousand tons		Year	Production, thousand tons	
	Exports	Imports		Exports	Imports
1950	25,468	347	1963	47,078	267
1951	56,722	292	1964	47,969	293
1952	47,643	262	1965	30,181	184
1953	33,760	227	1966	49,302	178
1954	31,041	299	1967	49,528	227
1955	51,277	337	1968	30,637	224
1956	68,553	356	1969	36,234	109
1957	76,446	367	1970	20,944	36
1958	50,293	307	1971	36,633	111
1959	37,253	375	1972	35,960	47
1960	36,541	260	1973	52,903	127
1961	34,970	164	1974	59,926	2,080
1962	38,413	232	1975	66,000	1,105

Figure 7 indicates the estimated production of coal in the United States to the year 2020. It indicates that coal production is expected to rise substantially during the near future. This rise in production is not expected to be caused so much by the preference for coal but rather by the shortage of other energy sources.

COAL PRICE PROJECTION

There are a large number of factors that may have an influence on the future price of coal. The magnitude of the effect of most of these is highly subjective. For the most part, these factors are trends that are perceived to be developing or that are expected to develop. It is not clear in some cases if or when some events that could have a major effect on the price of coal will occur.

Table 16 lists some of the factors that are expected to tend to raise the price of coal in the future and Table 17 lists some of the factors that will tend to restrain coal prices. Some of the factors in these tables, along with historical prices, are discussed and an estimate of future coal prices is developed.

The historical price of coal was obtained for the period 1890 to the present time and is shown in Table 18. Shown are the prices for each year in then year dollars. These prices were then corrected for inflation by two methods (Consumer Price Index and Gross National Product Implicit Deflator) and expressed in terms of 1975 dollars as shown in the

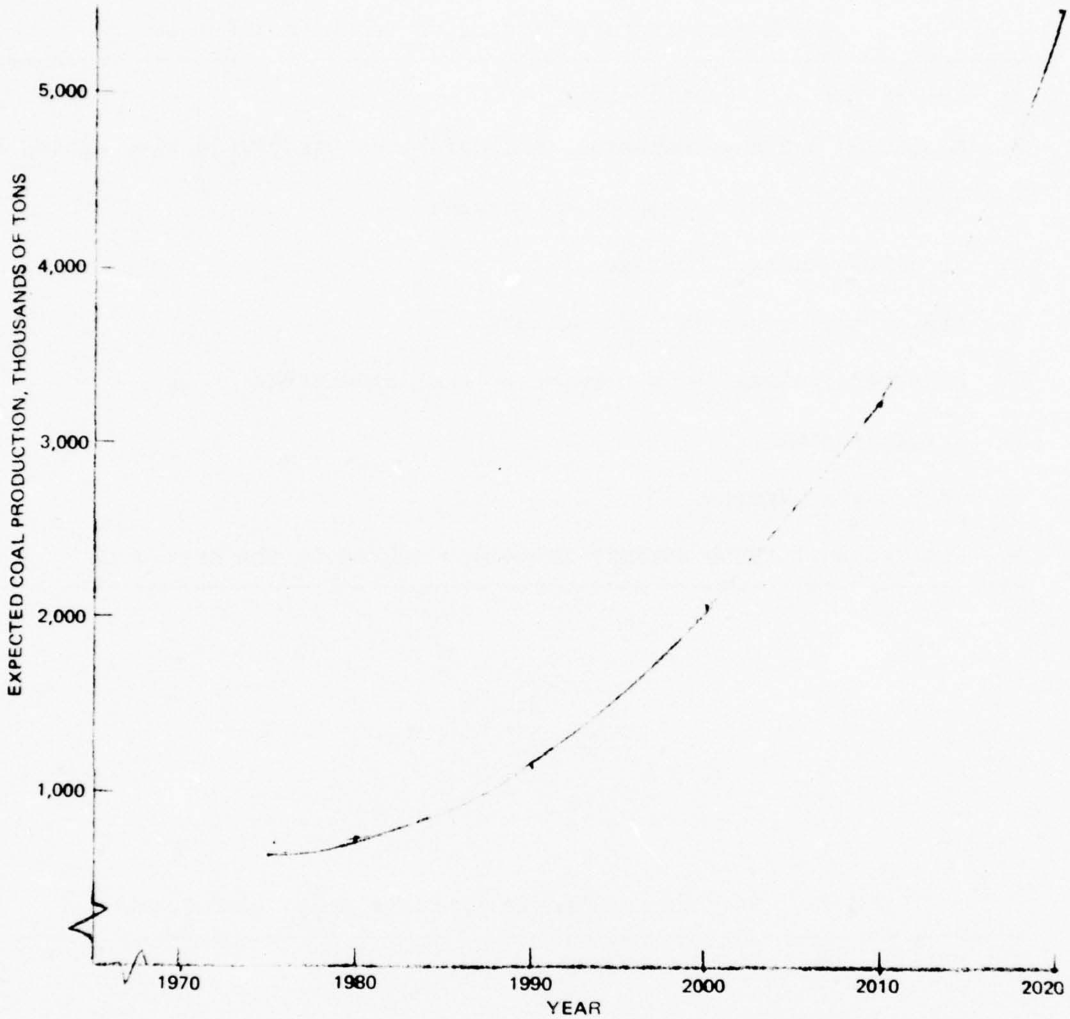


FIGURE 7. Estimated Production of Coal in the United States to the Year 2020.

TABLE 16. Factors Tending to Raise Coal Prices.

1.	Safety and health legislation
2.	Pollution and environmental considerations associated with mining coal
3.	Sympathy to oil and gas price changes
4.	Perceived energy shortage
5.	Higher real wages for coal miners
6.	Need for capital for expansion of coal production
7.	Price gouging
8.	Increasing exports
9.	Limited ability to satisfy increased demand in the near term

TABLE 17. Factors Tending to Restrain Coal Price Raises.

1.	Present return on investment is high
2.	Labor is relatively cheap
3.	Increasing percent of coal is from strip mines where costs are lower
4.	Demand is not growing fast
5.	Large reserves exist
6.	Segmented, competitive industry
7.	Waste disposal (ash and sulphur) problems
8.	Pollution and environmental considerations associated with burning coal

TABLE 18. Coal Cost Per Ton.

Year	Average cost per ton		
	Then year dollars	1975 dollars (CPI correction)	1975 dollars (GNPID correction)
1890	0.99		
1891	0.99		
1892	0.99		
1893	0.96		
1894	0.91		
1895	0.86		
1896	0.83		
1897	0.81		
1898	0.80		
1899	0.87		
1900	1.04		
1901	1.05		
1902	1.12		
1903	1.24		
1904	1.10		
1905	1.06		
1906	1.11		
1907	1.14		
1908	1.12		
1909	1.07		
1910	1.12		
1911	1.11		
1912	1.15		
1913	1.18	6.34	
1914	1.17	6.20	
1915	1.13	5.92	
1916	1.32	6.44	
1917	2.26	9.37	
1918	2.58	9.11	
1919	2.49	7.64	7.64
1920	3,75	9.94	10.09
1921	2.89	8.61	9.08
1922	3.02	9.57	10.00
1923	2.68	8.36	8.68
1924	2.20	6.84	7.22
1925	2.04	6.18	6.55
1926	2.06	6.20	6.61
1927	1.99	6.09	6.53
1928	1.86	5.77	6.03
1929	1.78	5.52	5.77

TABLE 18. (Contd.)

Year	Average cost per ton		
	Then year dollars	1975 dollars (CPI correction)	1975 dollars (GNPID correction)
1930	1.70	5.41	5.75
1931	1.54	5.39	5.87
1932	1.31	5.10	5.52
1933	1.34	5.51	5.79
1934	1.75	6.95	7.11
1935	1.77	6.85	7.27
1936	1.76	6.74	6.95
1937	1.94	7.18	7.57
1938	1.95	7.35	7.61
1939	1.84	7.05	7.27
1940	1.91	7.24	7.45
1941	2.14	7.73	7.62
1942	2.36	7.69	7.46
1943	2.60	7.98	7.49
1944	2.92	8.82	8.26
1945	3.06	9.06	8.42
1946	3.44	9.39	8.84
1947	4.16	9.90	9.61
1948	4.99	11.08	10.88
1949	4.88	10.93	10.49
1950	4.84	10.75	10.31
1951	4.92	10.14	9.64
1952	4.90	9.90	9.46
1953	4.92	9.84	9.40
1954	4.52	8.94	8.59
1955	4.50	9.00	8.51
1956	4.82	9.50	
1957	5.08	9.65	
1958	4.86	9.04	8.31
1959	4.77	8.78	
1960	4.69	8.44	7.79
1961	4.58	8.20	
1962	4.48	7.44	
1963	4.39	7.64	
1964	4.45	7.70	
1965	4.44	7.55	6.93
1966	4.54	7.49	
1967	4.62	7.39	
1968	4.67	7.19	6.49
1969	4.99	7.19	6.64

TABLE 18. (Contd.)

Year	Average cost per ton		
	Then year dollars	1975 dollars (CPI correction)	1975 dollars (GNPID correction)
1970	6.26	8.51	7.95
1971	7.07	9.26	8.55
1972	7.06	8.83	8.26
1973	8.53	10.15	9.47
1974	15.75	16.82	16.70
1975	18.75	18.75	18.75

table. It is readily apparent that the two methods of correcting the cost of coal for inflation are nearly equivalent. For this reason, the Consumer Price Index correction was used for the coal cost values. These prices are mine mouth prices. They do not include transportation costs.

The safety and health of coal miners is of continuing concern. There has been a concerted effort in the past by the industry to improve the injury rate. Substantial progress has been made as shown by Figure 8 (Ref. 7). The improvement has, no doubt, been enhanced by legislation from time to time. The Federal Coal Mine and Safety Act of 1969 is the latest example of federal legislation to improve the safety and health of coal miners.

As shown in Figure 8, the fatality rate declined steadily over the years. This trend is encouraging; however, Figure 9 (Ref. 8) indicates that both the severity rate and frequency rate of injuries for underground coal mining are both substantially higher than for any other industry. For this reason, additional safety and health measures are expected. These will substantially increase the future price of coal in the United States.

Table 19 (Ref. 9) shows the trend of the effect of the present safety and reclamation requirements on mining costs for specific examples of mines. This table illustrates the total cost impact, including amounts spent for the additional equipment and personnel, required to satisfy the regulations. As coal mines are brought into full compliance with the law, the costs shown in Table 19 are expected to increase rapidly.

The earnings for various coal industry occupations are shown for 1972 and 1973 in Table 20 (Ref. 9). These wages are low in comparison to other major industries. They are expected to increase at a rate exceeding the average of other industry for an extended period of time.

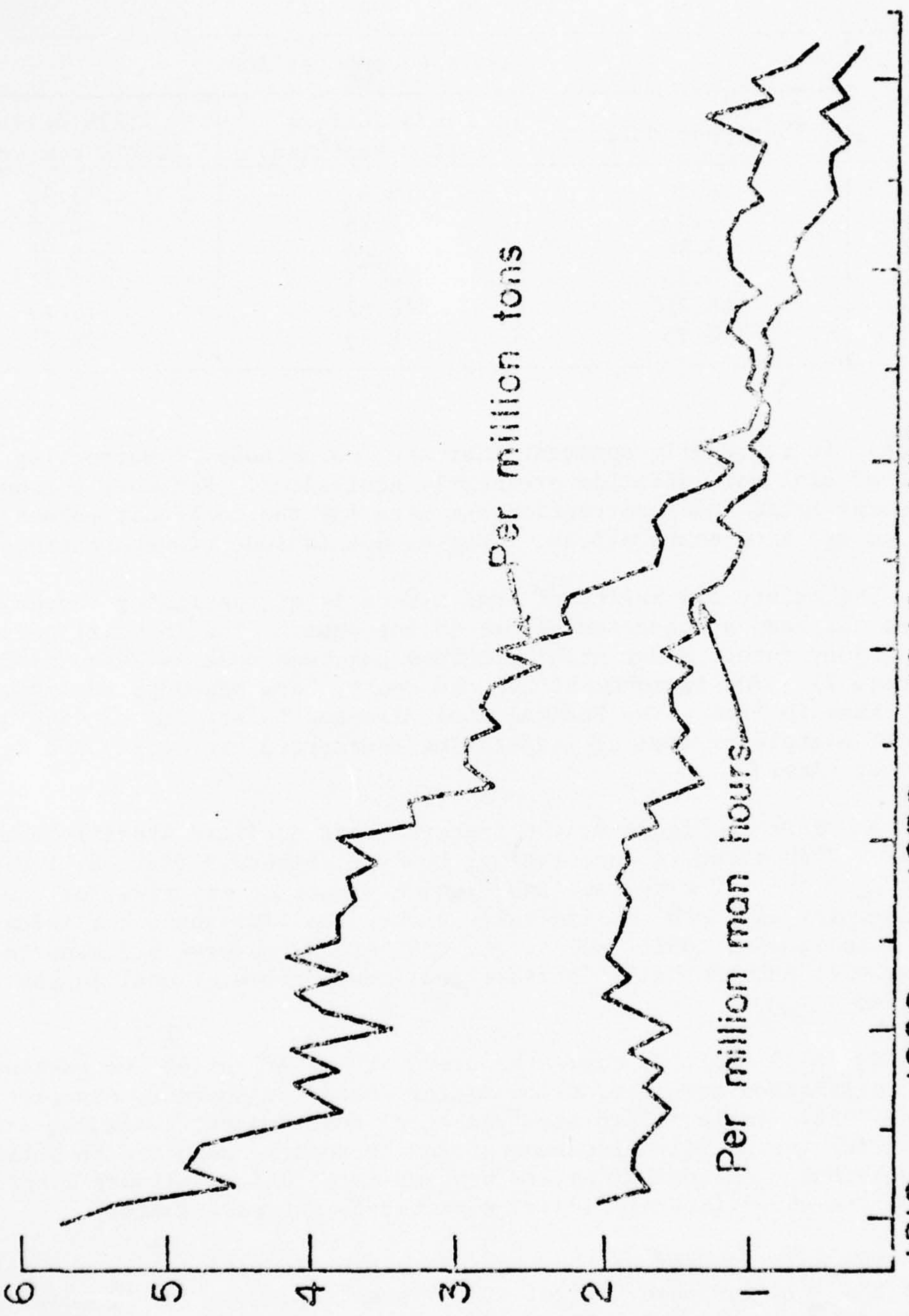


FIGURE 8. Underground Mine Fatalities.

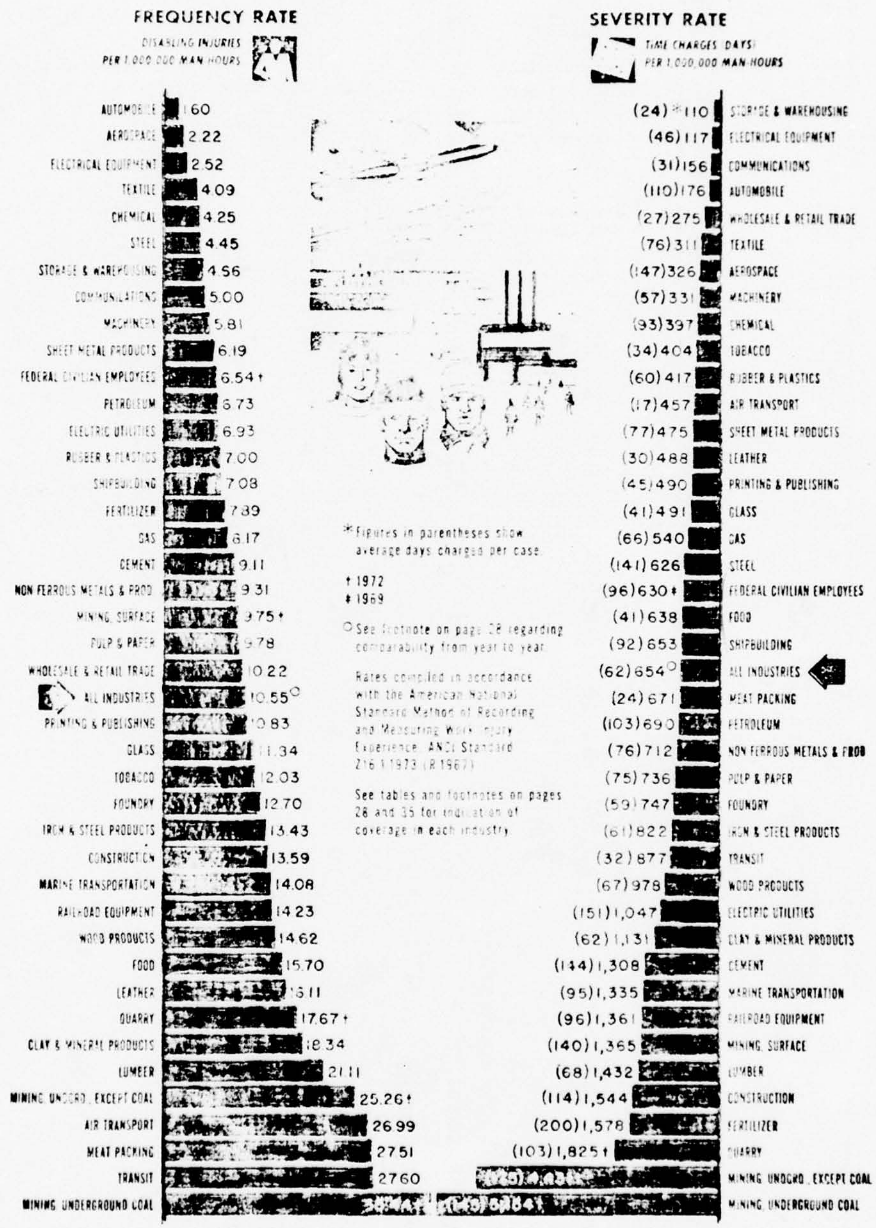


FIGURE 9. 1973 Injury Rates, Reporters to National Safety Council.

TABLE 19. Effect of the Safety and Reclamation Requirements on Mining Costs.

1966-1973
(Dollars per Ton)

	1966	1967	1968	1969	1970	1971	1972	1973
Illinois Deep Mine								
Total mining cost	$3.99	$4.18	$4.38	$4.69	$5.32	$5.66	$6.01	$6.39
Reclamation	0	0	0	0	0.02	0.03	0.05	0.05
Health and safety	0	0	0	0.10	0.50	0.60	0.70	0.75
Reclamation plus health and safety as a percentage of total	0%	0%	0%	2.1%	9.8%	11.1%	12.5%	12.5%
Eastern Kentucky Punch Mine								
Total mining cost	$3.96	$4.14	$4.34	$4.59	$5.08	$5.41	$5.66	$6.08
Reclamation	0	0	0	0	0.02	0.03	0.05	0.05
Health and safety	0	0	0	0.05	0.30	0.40	0.40	0.50
Reclamation plus health and safety as a percentage of total	0%	0%	0%	0.1%	6.3%	7.9%	8.0%	9.1%
Montana Surface Mine								
Total mining cost	$1.69	$1.80	$1.92	$2.04	$2.17	$2.31	$2.45	$2.66
Reclamation	0	0	0	0	0.02	0.05	0.10	0.15
Reclamation as a percentage of total	0%	0%	0%	0%	0.9%	2.2%	4.1%	5.8%
Eastern Kentucky Contour Surface Mine								
Total mining cost	$3.37	$3.53	$3.69	$3.86	$4.09	$4.33	$4.57	$4.78
Reclamation	0.05	0.05	0.05	0.05	0.10	0.15	0.20	0.25
Reclamation as a percentage of total	1.5%	1.4%	1.4%	1.3%	2.4%	3.5%	4.4%	5.2%

TABLE 20. **Earnings for Various Coal Industry Occupations.**

	Daily Wage Rate	
	November 1972	November 1973
Underground Occupations*		
Continuous Mining Machine Operators, Electrician, Mechanic, Fire boss, Longwall Machine Operator, Welder	$45.75	$50.00
Cutting Machine Operator, Dispatcher, Loading Machine Operator, Machine Operator's Helper, General Repairman-Welder, Roof Bolter	43.75	47.25
Driller, Shooter, Dumper, Construction, Faceman	41.75	44.75
Motorman, Shuttle Car Operator	40.45	43.25
Beltman, Bonder, Brakeman, Bratticeman, General Laobr, Electrician Helper, Mason, Mechanic Helper, Pumper, Tinkerman, Trackman, Wireman	40.00	42.75
Laborer - Unskilled	39.75	42.25
Surface Mine Occupations†		
Loading Shovel Operator, Overburden Machine Operator, Master Electrician	46.00	50.00
Electrician, Machinist, Mechanic, Welder-First Class, Shovel-Dragline Oiler	42.50	46.00
Mobile Equipment Operator, Repairman, Stationary Equipment Operator, Welder, Driller-Shooter, Groundman	40.90	43.75
Tipple Attendant, Electrician Helper, Machinist Helper, Mechanic Helper, Repairman Helper	39.50	42.00

TABLE 20. (Contd.)

	Daily Wage Rate	
	November 1972	November 1973
Surface Mine Occupations† (continued)		
Car Dropper, Car Dumper, Car Trimmer, Samples, Truck Driver Service, Utility Man	$39.00	$41.50
Laborer - Unskilled	38.85	41.25
Occupations in Preparation Plants and Other Surface Facilities - Deep and Surface Operations†		
Electrician, Machinist, Mechanic, Welder First Class, Prep. Plant Control Operator	41.50	45.00
Mobile Equipment Operator, Repairman, Stationary Equipment Operator, Welder Railroad Car Loader Operator	40.40	43.50
Tipple Attendant, Dock Man, Electrician Helper, Machinist Helper, Mechanic Helper	39.15	41.75
Car Dropper, Dumper, Trimmer, Sampler, Bit Sharpener, Truck Driver Service, Equipment Service, Prep. Plant Utility Man, Surface Utility Man	38.65	41.25
Laborer - Unskilled	38.40	41.00

Note: General Pay Provisions: Time and one-half pay for overtime beyond (1) 40 hours or (2) 36-1/4 hours. All Saturday work at time and one-half pay, Sunday work at double-time. Holidays (nine provided) worked paid at triple-time rate. Fourteen-day vacation for all employees with an additional day per year for each year's continuous employment beyond 10 years up to 19 years.

* Daily rate, underground occupations, based on portal-to-portal 8-hour day, 40 hour (Monday-Friday) week.

† Daily rate based on 7-1/4-hour (Monday-Friday) week.

Source: Provided by National Bituminous Wage Agreement of 1971.

Figure 10 (Ref. 10) shows the recent action of both spot and contract coal prices. There is a large difference between the spot and the contract price of coal for the period shown. This is not normal. About 80% of coal is sold on long term contracts and the remainder on the ''spot'' or open market. The oil embargo caused an increased demand for coal during this period. This increased demand for coal caused the spot prices to rise significantly because it couldn't be met from increased production due to the required lead time for new coal mine openings or expansion of existing mines. It is also felt that coal prices rose in sympathy to the higher oil prices.

The coal industry has the capability of large increases in coal production. It cannot, however, meet sudden unexpected increases in demand. These unexpected increases in demand will tend to sharply raise the price of coal for short periods of time. It then could go back down as the supply rises to meet demand. It appears, however, that the price of coal or any other similar commodity will not usually go completely back to the original price.

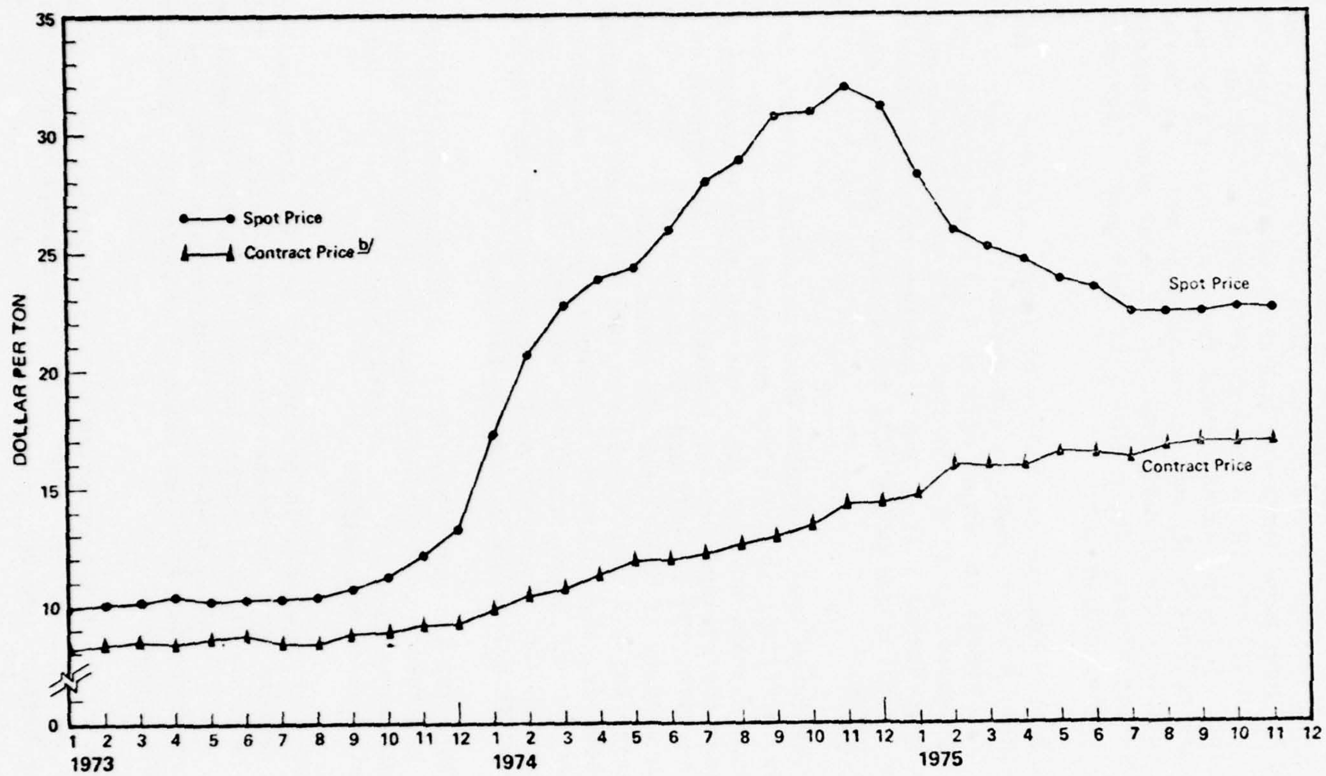
There are few large coal companies whose principal product is coal. It is, therefore, difficult to calculate return on investments for the industry. It does appear, however, that the return on investment for coal mines is near the average for all industrials. It appears to have been about 15% in 1970, 13% in 1972 and 10% in 1972 (Ref. 10). This compares with an average of 10-11% for all industrials for these years. In 1973 the average for all industrials was 14%, while coal remained at 10%. In 1974, however, the return on investment for coal companies rose to 25% while that for all other industries was 14%. It appears that profits from coal mining can adequately meet the demand for increased production as long as it occurs in an orderly fashion.

Table 21 (Ref. 10) indicates the shares of total production of the top four, eight and twenty coal mining firms. It is apparent that the industry is highly segmented. It is unlikely that coal prices can be raised by manipulation of the market.

The percentage of coal that is produced by surface mining methods has been rising rapidly over the years (see Figure 11 (Ref. 7)). This is expected to act to restrain coal prices because it is the cheapest method of mining coal. A difficulty, however, is that western strip coal mines are generally long distances from the place of consumption. This means the transportation costs are high.

Land reclamation costs are expected to be substantial for both surface and underground coal mining. The costs of reclamation are expected to be appreciably higher, however, for surface mines.

For surface mines, the mined areas will probably be returned to their original topography, but restoration requirements and capabilities will vary with location. For example, restoring the land to its original



a/ F.P.C., Monthly Fuel Cost and Quality Information, news releases; based on Form 423 reports.

b/ Average price of current deliveries of coal on long-term contracts.

FIGURE 10. Electric Utility Steam Coal Prices.[a]

TABLE 21. Bituminous Coal Industry Concentration Ratios: Shares of Total Production (Percent).[a]

Number of Firms	1955	1960	1965	1970	1971	1972	1973	1974
Top 4	17.8	21.4	26.6	30.2	27.8	30.2	29.1	26.6
Top 8	25.4	30.5	36.3	40.7	37.6	40.0	39.1	36.7
Top 20	39.5	44.5	50.1	56.5	52.2	55.8	54.9	51.2

a/ A list of the top 20 coal producers and their parent companies is given in Appendix B of Ref. 10.

SOURCES: FTC - Concentration in the U.S. Energy Industry, 1974.

Keystone Coal Manual, and McGraw-Hill, for various years.

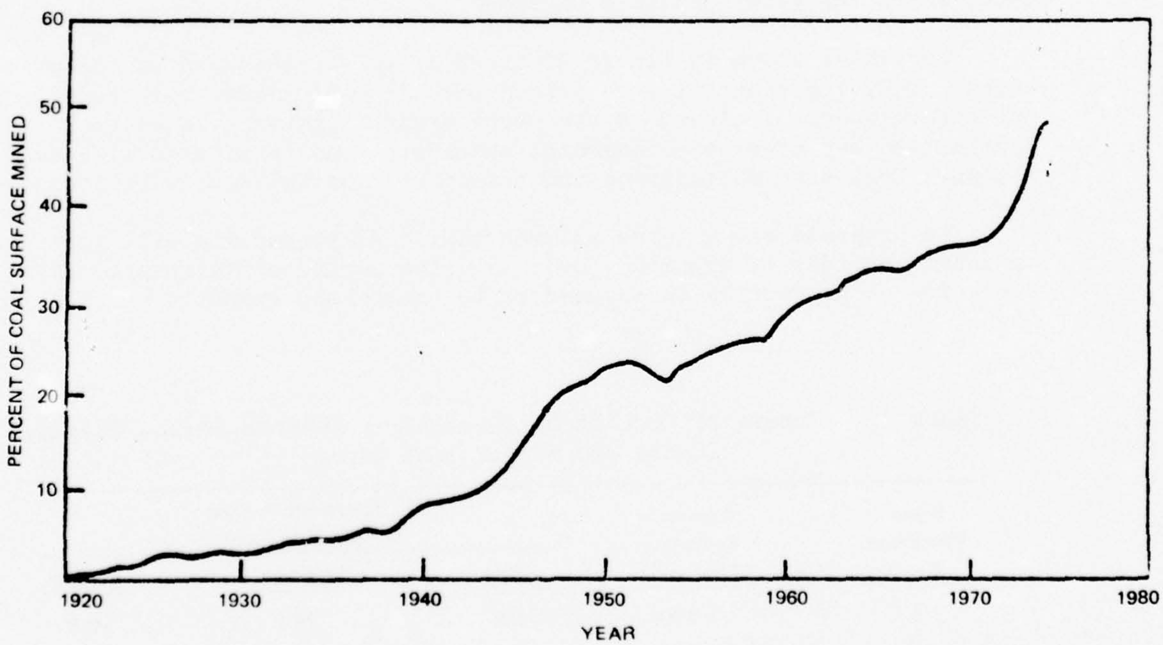


FIGURE 11. Increase in Coal Production by Surface Mining. (Adapted from Gouse and Rubin, 1973: III-5.)

form will be almost impossible when the thick Montana and Wyoming coal beds are mined. Revegetation in arid areas such as these is also a major problem.

The reclamation problems associated with underground mines vary from those of surface mines. The largest problem is the disposal of materials mined with the coal. Often coal is cleaned at the surface to remove these materials. These waste materials cannot be simply piled up and left because they may produce acid water runoffs when dissolved by rain.

Reference 11 is an indepth treatment of reclamation costs. It indicates that reclamation costs can run as high as $10 per ton of coal. Other studies (Ref. 5) indicate much lower reclamation costs as shown in Table 22.

The large coal reserves of the United States probably will be the largest restraint on future coal prices. These large reserves combined with the segmented industry are expected to jointly act to stabilize and restrain coal prices through the time period of interest.

Figure 12 presents the projections of future coal prices for the period 1975-2020. Shown are prices for three assumptions—optimistic, probable, and pessimistic. The optimistic and pessimistic values are intended to represent probable extremes.

The prices shown in Figure 12 are for freight-on-board at the mine mouth. They represent average prices for all coal mined, both surface and underground. Included in the price projections are the costs of reclamation and other environmental considerations associated with coal mining. Coal desulphurization and transportation costs are not included.

The probable price curve assumes that coal production will increase by about an order of magnitude over the time period of interest. This expansion of production is assumed to be smooth and steady.

TABLE 22. Impact of Cost of Reclamation in Western United States. (Cents per ton of coal mined)

Seam Thickness (Feet)	Approx. Recovery (Ton/Acre)	Reclamation Cost (Dollars/Acre)		
		$500	$1,000	$1,500
5	9,000	5.6	11.2	16.8
10	18,000	2.8	5.6	8.4
20	36,000	1.4	2.8	4.2

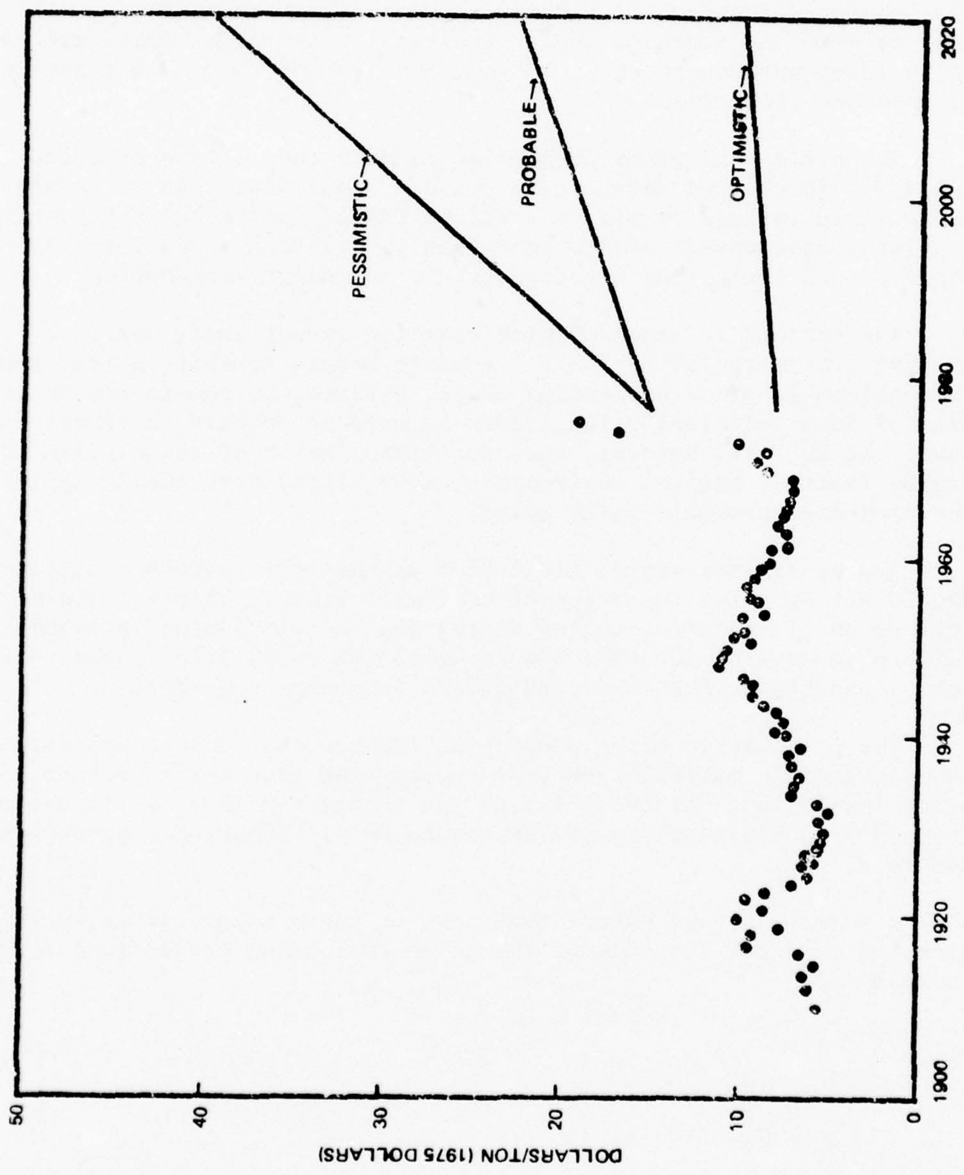


FIGURE 12. Coal Price Projections, FOB Mine Mouth.

In order for the probable price curve to occur, it will be necessary for federal coal leases to be granted for substantial acreage. The probable price curve assumes that safety, health, environmental and reclamation related laws and social pressures will become more difficult for the coal mining industry. It assumes, however, that the industry will be able to grow and overcome these problems. Substantial costs are expected to be incurred because of these concerns. These costs are expected to increase with time.

The optimistic price projection assumes that events or trends which would be expected to depress the price of coal will tend to happen. These would include no oil embargo, no United States balance-of-payments problems, development of low cost desulphurization technology, low coal exports, and lower than expected growth in energy consumption.

The optimistic price assumes that the recent rapid and large increase in coal prices caused by the oil embargo return to their normal levels. The optimistic price projection could, perhaps, be considered an extension of long term coal price trends because it appears to simply extend them. It is felt, however, that an extrapolation of recent (last 5 years) trends (safety, health, environment, cost, etc.) more nearly approximates the projected probable price curve.

The pessimistic price projection assumes that events or trends which should act to raise the price of coal will tend to happen. These would include an oil embargo, United States balance-of-payments problems, failure to develop low cost desulphurization technology, large coal exports, and higher than expected growth in energy consumption.

The pessimistic price projection assumes that coal consumption will show large fluctuations from year to year and tend not to return to the price levels that existed prior to the unexpected increase in demand. These demand fluctuations may be caused by oil embargoes, government controls, etc.

A summary of the extent that some of these major events would be expected to occur for each of the three coal price projections is shown in Table 23.

TABLE 23. Summary of Major Factors Considered in Coal Price Projections.

Factor	Optimistic Case	Probable Case	Pessimistic Case
Energy Demand Level	Lower than expected	About as expected	Substantially higher than expected
Foreign Oil Embargoes	None	Short term or ineffectual only	Extended and effective
U.S. Balance of Payments	No problem	Some problem	Severe problems
Coal Miner Wages	No real growth	1-3% real growth	High real growth
Coal Desulphurization Technology	No large costs or problems involved	Costs are moderate and process works	Technology is expensive and not very practical
Coal Exports	Remain low	Continue present growth rate	Become very large
Acceptance of Nuclear Electric Generating Plants	Larger numbers accepted	Large numbers accepted	Not widely accepted
Safety, Health, Environmental and Reclamation Laws	Not overly restrictive	Restrictive but manageable	So restrictive as to greatly hinder production and increase costs
Coal Industry Control	Highly competitive	Competitive, considerable govt. control	Largely government controlled
Coal Demand Level	Steadily increasing	Relatively steady increases	Widely fluctuating demand
*Synthetic Coal Gas Technology	Widely adopted	Widely used after 1985	Not economical
*Synthetic Oil from Coal	Widely adopted	Widely used after 1990	Not economical

*Not expected to be major factors in future coal prices.

NATURAL GAS

INTRODUCTION

In the past, natural gas consumed in the United States has been supplied by conventional oil (associated) and gas (nonassociated) wells located in the contiguous 48 states with a small fraction supplied by overland pipeline imports from Canada and Mexico. Natural gas is not only the cleanest but also one of the lowest cost fuels. The demand has been steadily increasing because of government price regulation. For the past several years the conventional sources have not been able to meet this expanding demand, which has exceeded both the current productive capacity and its projected resource base. The government is currently increasing selected well-head prices in an effort to encourage and stimulate new gas exploration as well as to increase production from existing fields.

In order to fill this unsatisfied demand, utility companies are seeking alternate sources such as the production of high Btu (pipeline) gas from coal, synthetic gas from liquid hydrocarbon feedstocks, imported liquid natural gas (LNG), and pipeline gas from the Alaska North Slope.

Technology breakthrough in new areas such as nuclear stimulation and massive hydraulic fracturing of low-permeability reservoirs, the extraction of gas from organic wastes, and the use of nuclear heat to generate pipeline gas from coal are also possible.

In this section, the status of the natural gas reserves are briefly discussed, the projected supply and cost of natural gas from each source (conventional, imported, and synthetic) estimated, and the results summarized to yield the most probable supply and aggregate cost of natural gas through the year 2020. In conjunction with the most probable cost projection, optimistic and pessimistic estimates are included.

NATIONAL POLICY AND OTHER ASSUMPTIONS

As one reads such digests as BNA's Weekly Energy User's Report and the FPC News and periodicals such as Business Week and Barron's, it becomes apparent that the Nation's policy on natural gas is still in the formative stages. For the purposes of this report the following natural gas policy has been assumed:

Deregulation of new gas will occur in the near future, probably in calendar year 1977.

End use priorities will be established in the use of natural gas with the highest priority going to individual home owners, thus forcing industry to utilize other fuels.

The limitation on natural gas imports, currently set at 1 trillion cubic feet (Tcf) per annum, will either be lifted or raised to about 3 Tcf.

Other assumptions include:

All costs are represented as 1975 dollars.

All natural gas prices are well-head prices (this should be kept in mind when comparing natural gas prices with those of crude oil, which are retail prices).

The following abbreviations will be employed in this section:

Tcf $\triangleq$ trillion cubic feet

Mcf $\triangleq$ thousand cubic feet

Qcf $\triangleq$ quadrillion cubic feet

RESERVES

In 1974 the production of natural gas was 21.3 Tcf, a decrease of 6% from the previous year, causing concern about future supplies. Table 24 (Ref. 12) presents various estimates of remaining United States natural gas resources. It includes both proven and potential reserves.

TABLE 24. Estimates of U.S. Natural Gas Resources Remaining (including Alaska).

Source/Data	Undiscovered recoverable plus inferred resources (Tcf)	Proved* reserves (Tcf)	Total (Tcf)
Mobil Oil Corp. 1974	443 + 65	250	758
Moody** 1975	485 + 65	237	787
Nat. Acad. of Sciences 1975	530 + 118	237	885
U.S. Geological Survey 1975	(322-655) + 202	237	761-1094
Potential Gas Committee 1973	1146	266	1412

*Those known to exist which can be economically produced using conventional methods.

**Consulting geologist.

One can adopt an optimistic attitude and conclude that at the present rate of consumption there is ample natural gas. The American Gas Association (AGA) states that there is enough undiscovered gas to last through the year 2030 (Ref. 13). AGA also states that there are vast quantities of natural gas in hard-to-produce reservoirs in the Rocky Mountain region (estimated at 600 Tcf) and in the Eastern United States (estimated at 500 Tcf) awaiting the development of advanced fracturing techniques (nuclear, hydraulic) which would make extraction economical (Ref. 14).

There are, however, ominous signs that belie optimism. First, proved reserves of the United States monotonically increased up to 1967, peaking at 292.9 Tcf. With the exception of 1970, when 26 Tcf of proven reserves in the Prudhoe Bay field of Alaska's North Slope were added to the inventory, the proven year-end reserves have been on a downward trend, production having exceeded new reserves.

Another critical sign is the steady decline of the reserve-to-production ratio (R/P), a measure of the remaining years of proven reserves at the current level of production. In the past 10 years it has declined from 18.3 years (1964) to 11.1 years (1974).

A final significant parameter for assessing prospects for the future is the finding rate (Mcf/successful foot drilled). For nonassociated reserves* in the lower 48, the finding rate has dropped from 409 Mcf/foot in 1970 to 104 Mcf/foot in 1973.

These figures are summarized in Table 25 (Ref. 15, 16, 17).

The 1974 year-end reserve for the world was 2.16 Qcf, down from the 1973 figure of 2.23 Qcf (Ref. 18).

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*Free natural gas not in contact with nor dissolved in crude oil in the reservoir.

TABLE 25. United States Natural Gas Reserves, Reserve/Production Ratio, and Finding Rate: 1946-1974.

Year	Proved reserves (Tcf)	Reserve/production ratio (years)	Finding rate (Mcf/foot)
1946	159.7	32.5	
1947	165.0	29.5	
1948	172.9	28.9	
1949	179.4	28.9	
1950	184.6	26.9	
1951	192.8	24.3	
1952	198.6	23.1	
1953	210.3	22.9	
1954	210.6	22.5	
1955	222.5	22.1	
1956	236.5	21.8	
1957	245.2	21.4	
1958	252.8	22.1	
1959	261.2	21.1	
1960	262.3	20.1	
1961	266.3	19.9	
1962	272.3	20.0	
1963	276.2	19.0	
1964	281.3	18.3	
1965	286.5	17.6	
1966	289.3	16.5	662
1967	292.9	15.9	831
1968	287.4	14.8	613
1969	275.1	13.3	286
1970	290.7	13.2	409
1971	278.8*	12.6	379
1972	266.1*	11.8	284
1973	250.0*	11.1	104
1974	237.1*	11.1	not available
1975	222.2**	not available	not available

*Figures include 26 Tcf in Prudhoe Bay, Alaska (discovered in 1968).

**Preliminary.

PROJECTED SUPPLIES AND COSTS

Lower 48 Natural Gas

Supply. Table 26 shows the quantity of gas consumed from this source for the past 15 years (Ref. 17).

It is generally accepted that the future supply and production of continental United States natural gas will depend upon the outcome of the current debate being waged in Congress on the proposed deregulation of natural gas.

There have been a number of studies made on the effect of ''new'' gas price deregulation on near-future domestic gas supplies as well as projections in response to the current legislative bills on deregulation being considered in Congress. Needless to say, there is not agreement as to what the effect will be. Many feel that deregulation will stimulate the search for additional reserves. However, some believe that such an action is as much a potential means of reducing demand as increasing supply. They feel that the rising natural gas prices that deregulation will precipitate would act as an incentive for energy conservation as well as encourage conversions to alternative fuels (Ref. 19).

TABLE 26. Quantity of Gas Consumed.

Year	Natural gas consumed (Tcf)
1960	12.51
1961	13.01
1962	13.81
1963	14.56
1964	15.45
1965	16.03
1966	17.19
1967	18.17
1968	19.46
1969	20.92
1970	22.05
1971	22.68
1972	23.01
1973	22.97
1974	21.30
1975	20.20*

*Estimated

Table 27 shows the results of several of the studies.

TABLE 27. Effect of Deregulation of Natural Gas Prices on Production.

New gas deregulation study	Time period covered	Projected total production (Tcf)
Schwartz (Ref. 19)	1975-80	22.5 (1980)
Project Independence (Ref. 19)	1974-85	21.3 (1985)
FEA (Ref. 20)	1974-85	22.3 (1985)
AGA (Ref. 19)	1975-85	22.0 (1985)
GAO, Case 1 (Ref. 21)		18.7 (1985)
Case 2 (Ref. 21)		21.4 (1985)
Libary of Congress (Ref. 18)		25.0 (1985)

All of these studies, of course, exclude Alaska. The GAO study, Case 1, assumes new finds equal to the last 10 years of U.S. exploration. The writer feels that deregulation will stimulate the market such that future exploration will exceed that of the last 10 years, and consequently, that the 1985 projection of 18.7 Tcf is too low. Also, the Library of Congress' 1985 estimate of 25 Tcf is quoted as a maximum figure. Averaging the remaining clustered estimates for the supply of Continental United States natural gas in 1985 yields 21.8 Tcf. (It is interesting to note that if the low (18.7) and high (25) estimates are included in the averaging, the result is about the same.) Thus, assuming deregulation of new gas in 1977, the most probable projected supply is taken as a linear growth function from 1975's figure of 20.2 Tcf to 21.8 Tcf in 1985. After 1985, one of the studies indicates a leveling-off (viz, the Library of Congress study). However, others believe the supply will gradually diminish (Ref. 22). It appears probable that exploration stimulated by deregulation will peak in 1990 at 22 Tcf and, as alternate fuels become available, the demand and, consequently, the supply or yearly production will gradually decrease to 19 Tcf in 2020. The most probable trend is summarized in Table 28.

TABLE 28. Projected Supply of Lower 48 Natural Gas (Tcf).

1975	1980	1985	1990	1995	2000	2010	2020
20.20	21.00	21.80	22.00	21.80	21.50	20.50	19.00

Cost. Once deregulation of new gas occurs, it is predicted that the average well-head price of new gas will escalate immediately to the average intrastate price ($1.55/Mcf, first quarter 1976, Ref. 23), and will continue to rise (Ref. 24) reaching $1.75/Mcf within a short period of time (Ref. 21). In 1985 it is estimated the price will be $2.13/Mcf (Ref. 20). This agrees fairly well with one study (Ref. 25), which predicts the price will continue to escalate, but at a faster rate (e.g., 1990: $3.20, 2000: $4.80). Another simulation study (Ref. 26) has the price increasing at about the same rate (e.g., year 2000: $3.12). Assuming deregulation, it appears that cost will rise until 2000, as the SRI study assumes, and will then level off to about $3.25 to remain competitive with the projected price of the alternate gas sources (Alaska, LNG, SNG) which by that time will be contributing significantly to the supply.

The projected costs are summarized in Table 29.

TABLE 29. Projected Cost of Continental United States Natural Gas (1975 dollars)

1977*	1980	1985	1990	2000	2010	2020
1.75	1.90	2.13	2.63	3.12	3.25	3.75

*Time of deregulation

The projected most probable value of the supply and cost of Continental United States natural gas is displayed in Figure 13.

Alaska North Slope Gas

Supply. In 1968 a large (26 Tcf proven reserve) natural gas field was discovered on Alaska's North Slope with additional potential supplies (as yet undeveloped) estimated at 366 Tcf (Ref. 27). There are several plans for transporting the gas to the contiguous United States under consideration. The El Paso plan (Ref. 28) recommends building a pipeline from the field in Prudhoe Bay to a southern Alaskan port such as Valdez. At this point, the gas would be liquefied and transported via LNG tankers to a port in California (possibly Pt. Conception or Oxnard). It would then be regasified for distribution. The Arctic proposal (Ref. 29) is to build a pipeline all the way from the fields to the Canadian-United States border (at Minnesota). A third proposal, the Northwestern plan, which is similar to the Arctic proposal, has just been introduced into Congress (Ref. 30). The route and means for transporting the gas will probably be determined early in calendar year 1977.

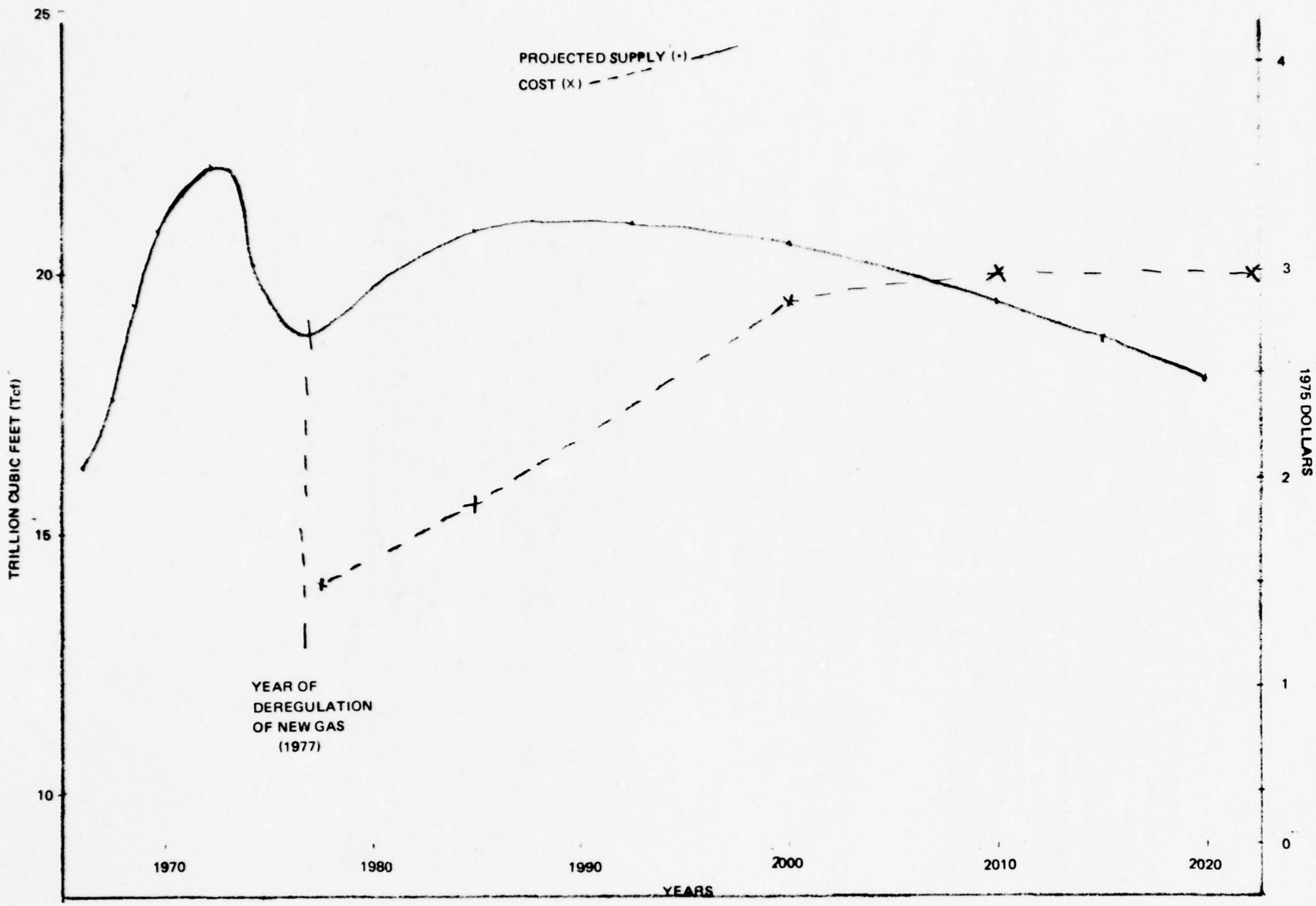

FIGURE 13. Natural Gas--Lower 48 Projected Supply and Cost.

Regardless of the outcome, the schedule for delivery is estimated to be 1.5 Tcf per year starting in 1986 and growing to a maximum of 3 Tcf per year in 2000 (Ref. 22). This level will probably be maintained through the year 2020. One constraint to the future supply from Alaska will be the pipeline size. This is estimated to allow for a maximum transmission of about 4.5 Tcf per year (Ref. 31). There is a strong likelihood that if the Arctic or Northwestern plan is selected Canadian gas will be transported through the line along with the Alaskan gas, particularly if the Canadian MacKenzie Delta and/or Arctic Island fields can be developed. Therefore, the 3.00 Tcf per year maximum is realistic. The projected supply for Alaskan North Slope gas is summarized in Table 30.

TABLE 30. Projected Supply of Alaskan North Slope Gas (Tcf).

1977	1985	1990	2000	2010	2020
0	1.50	1.80	3.00	3.00	3.00

Cost. To be able to combine and compare price estimates for Alaskan gas with those at the well-head in the continental United States, transportation costs must be included. Since the method and the means of transportation have not as yet been decided, this is speculative. It was assumed in one study (Ref. 26) that the cost of Alaskan gas would be $3.37 in the year 2001. Another study (Ref. 31) indicates an initial cost of $1.05/Mcf using the El Paso proposal (pipeline and LNG tankers to the West Coast). This seems low since another study (Ref. 32) projected a cost of $1.00-$1.50/Mcf for LNG from Algeria (which has since risen to $3.00) and this involves no cost for pipeline construction. Based on these inputs, the most probable cost of Alaskan gas is estimated to be $3.00/Mcf in 1986. It is anticipated that the price will remain at this level through 2020.

Synthetic Natural Gas from Liquid Hydrocarbons (SNG-L)

Supply. At one time liquid hydrocarbons were a promising source of synthetic natural gas because of the low price of liquid feedstock (e.g., naptha at five cents per Mcf). Thirteen synthetic gas plants are in operation or are under construction in the United States (Ref. 21). These plants were planned several years ago before the Arab oil boycott sharply increased prices. Rising costs will probably make synthetic gas from liquid feedstock unfeasible (Ref. 32).

However, it is likely that there will be a modest production of gas from this source starting at a level of .28 Tcf in 1980, decreasing to .12 Tcf in 2000, and then dropping to zero as new breakthroughs are made in high Btu coal gasification technologies. These estimates were obtained by averaging the projections in the references (Ref. 22 and Ref. 33) and are displayed in Table 31.

Cost. The cost of SNG will be governed by the price of imported oil to a considerable extent. The price of naptha has risen from $.05 to $1.10/Mcf (Ref. 32). The estimated price for SNG-L currently lies in the $3.32-$4.76/Mcf range (Ref. 13). Allowing for a nominal increase in the cost of liquid feedstock, it is assumed that the price of SNG-L will be $4.00/Mcf in 1980 and will rise to $6.00/Mcf in 2000 due to rising import prices. These costs are summarized in Table 32.

TABLE 31. Projected Supply of SNG-L (Tcf).

1977	1980	1985	1990	2000	2010
0	.28	.23	.18	.12	0

TABLE 32. Projected Cost of SNG-L (1975 Dollars).

1977	1980	1985	1990	2000	2010
0	$4.00	$4.50	$5.00	$6.00	0

Synthetic Natural Gas from Coal (SNG-C)

Supply. The first generation (Lurgi) technology was established by the Germans during World War II. Projects utilizing the Lurgi process are currently being pursued. However, a second generation technology, which is simpler, cheaper, and more efficient, will be available within a very short time.

Rather than approve loan guarantees that would predominantly underwrite the on-going Lurgi projects, the Congress will probably be more supportive of the development of the second generation process (Ref. 34).

High Btu gas from coal is a substitute natural gas. The process is still in the developmental stages.

There are many studies that predict the production of SNG-C: Edison Electric Institute and Data Resources, Inc. (Ref. 35), Department of the Interior (Ref. 22), National Petroleum Council and Syn. Gas (Ref. 16) and the Federal Power Commission (Ref. 36 and 37). All pretty much agree that there will be .3-.4 Tcf available in 1980, rising to 1.0-1.5 Tcf in 1985. Two studies, Syn. Gas (Ref. 16) and FPC (Ref. 36) predict about 3.0 Tcf in 1990 and four studies, Electric Power Research Institute, Data Resources, Inc. (Ref. 35), Department of the Interior (Ref. 22), and National Petroleum Council (Ref. 16) indicate 3.6-7.8 Tcf available in 2000. Taking the average of these studies and extrapolating the curve to 2020 yields the most probable production of SNG-C through 2020.

Considering the current thinking, which emphasizes development of second generation technology, it is expected that all of these dates will slip by about five years.

The results are summarized in Table 33.

TABLE 33. Projected Supply of SNG-C (Tcf).

1977	1985	1990	1995	2000	2010	2020
0	.35	1.25	3.00	3.50	4.00	5.00

Cost. In a detailed economic analysis on coal gasification (Ref. 34), a relationship was established showing the effect of the incremental rise in coal costs on the price of SNG-C. The basic assumptions in developing this relationship were:

Process efficiency, 60%.
Capital charges supplies via a public utility financing method.
Plant operating cost escalation included.
Method applies to first and second generation processes.

It is estimated that synthetic natural gas generated using the Lurgi process would today cost $4.00/Mcf, while a typical second generation process would yield gas at about 20% less, i.e., $3.20/Mcf (Ref. 34).

The determining factor for escalation in the cost of synthetic gas will be the price of coal. The coal used to run synthetic gas plants will be from new mines which is more expensive than average coal costs. It is assumed that new mine coal will run 10% higher than the average price. It is further assumed that after 20 years the price for new mine coal would be the same as the average price.

The first synthetic gas from coal will be from the Lurgi process starting in 1985, at a cost of $4.10/Mcf. The cheaper second generation process will phase in around 1990, at a cost of $3.40/Mcf. The cost pattern for synthetic gas from coal is displayed in Table 34.

TABLE 34. Projected Cost of SNG-C (1975 Dollars).

	1980	1985	1990	2000	2010	2020
1st generation		4.10				
2nd generation			3.40	3.50	3.65	3.80

*Pipeline gas from Alaska is not considered an import.

Imported (Canadian) Pipeline Gas

Supply. Most of the imported pipeline gas comes from Canada* with a small amount coming from Mexico. Even though there have been some recent promising oil finds, the future natural gas potential of Mexico is unknown. Consequently, in establishing the most probable projected supply, it will be assumed that future pipeline imports will be exclusively from Canada. Table 35 shows the amount of natural gas piped in from Canada over the past few years (Ref. 17).

TABLE 35. Imported Canadian Pipeline Gas (Tcf).

1968	0.61
1969	0.68
1970	0.78
1971	0.91
1972	1.01
1973	1.03
1974	0.90
1975	0.90*

*Preliminary.

Proven reserves in Canada at the end of 1975 were 57 Tcf (Ref. 13). This included an estimate for the undeveloped MacKenzie Delta region but not for the Arctic Islands.

As can be seen from the table, Canada imports declined in 1974. The Canadian Government has outlined a 10-year program for making the country less dependent on foreign oil suppliers (Ref. 38). Though the new national energy strategy did not reflect on future export policies regarding the United States, Canada's National Energy Board has scheduled hearings for October 1976 at which time it will reconsider its oil export policies. It is anticipated that because of Canada's energy strategy, the export of natural gas will cease by 1980.

Cost. Canada's attempt to attain energy self-sufficiency already has been reflected in the recent announcement of an increase in export prices, \$1.80/Mcf in September 1976 to be raised to \$1.94 in January 1977 (Ref. 39). It is assumed that the price will rise to \$2.50/Mcf in 1980 when Canada ceases to export natural gas. These prices are summarized in Table 36.

TABLE 36. Projected Price of Imported Canadian Pipeline Gas.

1976	1977	1980
\$1.80	\$1.94	\$2.50

Imported Liquefied Natural Gas (LNG)

Supply. Imported liquefied natural gas recently has loomed as an important factor in attempts to alleviate the energy shortage. Except in the Canadian pipeline, importation of natural gas first requires its reduction to a liquid so that useful amounts can be transported. Once the gas has been transported, it is regasified. Until quite recently, most LNG facilities have been devoted to liquefying domestic gas for peak load service in gas distribution operations.

Small quantities of LNG have been imported in the past; for example, 0.004 Tcf from Algeria in 1973 (Ref. 40). However, none was imported in 1974. Eleven projects by domestic oil companies for importation of LNG from Algeria and Indonesia have been approved and several more are under consideration (Ref. 32). Nigeria and the USSR are also future potential sources for LNG. Projected deliveries of LNG are expected to be 0.4 Tcf in 1977 (Ref. 12) and rising to 1 Tcf in 1980 (Ref. 41). A White House proposal has been made to limit LNG imports to 1 Tcf/year by 1985 (Ref. 41). However, this proposal has been termed unrealistic (Ref. 28) and will probably be reconsidered (see National Policy Assumptions). It is estimated that the most that can be brought into the United States by 1985 is 3.04 Tcf, with a realistic figure being 2-2.5 (Ref. 28). Most probably, imported LNG supplies will be 0.4 Tcf in 1977 rising to a value of 2.0 in 1985 and leveling off to a constant 2.5 in 1990.

This agrees fairly well with several recent studies by Hardy in 1974 and Linden in 1973 (Ref. 16) as well as the Shell Corporation (Ref. 33). Projected LNG supplies are displayed in Table 37.

TABLE 37. Projected Imported LNG Supply (Tcf).

1977	1980	1985	1990	2000	2020
0.40	1.07	2.00	2.50	2.50	2.50

Cost. In order to compare the price of imported LNG with the well-head price of domestic gas, the cost for liquefaction, transportation, and regasification must be added onto the price of the gas at the source. Original contracts for LNG from Algeria had to be renegotiated recently since the new source price was escalated to about four times that originally agreed upon (from $0.33 to $1.25/Mcf) (Ref. 32). The total price for Algerian LNG at port of arrival will be $3.00/Mcf. In addition, the cost of Indonesian LNG to be delivered to the West Coast also will be $3.00/Mcf (Ref. 32). One company was able to avoid the tremendous price increase. El Paso Natural Gas has negotiated with Sonatrach to import Algerian gas at $1.50/Mcf. However, it appears that the trend has been set and the cost per Mcf for other contracts will be at least $3.00. A sensitivity analysis conducted several years ago (Ref. 26) assumes the price projections for imported LNG as shown in Table 38. The nominal estimate is considered to be the most probable.

The projected cost of imported LNG is summarized in Table 39.

TABLE 38. Price Projections for Imported Liquefied Natural Gas (LNG).
(in dollars per Mcf)

	1975	1986	1995	2001
Nominal	3.02	3.98	4.38	4.57
Low	3.02	2.41	2.63	2.82
High	3.76	4.95	5.46	5.69

TABLE 39. Projected Cost of Imported LNG (1975 dollars).

1977	1980	1985	1990	2000	2010
3.00	3.50	3.90	4.10	4.50	4.90

PROJECTED AGGREGATE SUPPLY AND COST

The projected aggregate supply of natural gas (domestic, imported and synthetic) is displayed in Figure 14. The complete cost/supply breakdown is shown in Table 40, including the aggregate or weighted average cost computations. This projected aggreg te cost is plotted in Figure 15.

EXTREME COST PROJECTIONS

The previous discussion has dealt with the most probable cost estimate. In this section an optimistic and pessimistic estimate are considered.

Optimistic Estimate

The following future events, if they occurred, would lead to lower natural gas costs.

- Deregulation of new gas leads to intense exploration and the finding of a number of large reserves both within the continguous United States and the Atlantic outer continental shelf.

- Advanced fracturing techniques become available to allow for the economic recovery of gas from reservoirs locked in near-impermeable geological formations in the Rocky Mountains and the Eastern United States.

- Large untapped natural gas deposits in Canada's MacKenzie Delta and Arctic Islands confirmed as proven resources.

- Technological breakthroughs in the liquefaction, regasification, and transportation of natural gas occur leading to the inexpensive importation of LNG from Algeria, Russia, Nigeria and Indonesia.

- Stabilization of OPEC oil prices.

- Second generation coal gasification technology developed earlier than anticipated, accompanied by a stabilization of coal prices (i.e., optimum projected coal prices discussed elsewhere in this report).

- Large Mexican oil finds verified along with extensive associated natural gas reserves.

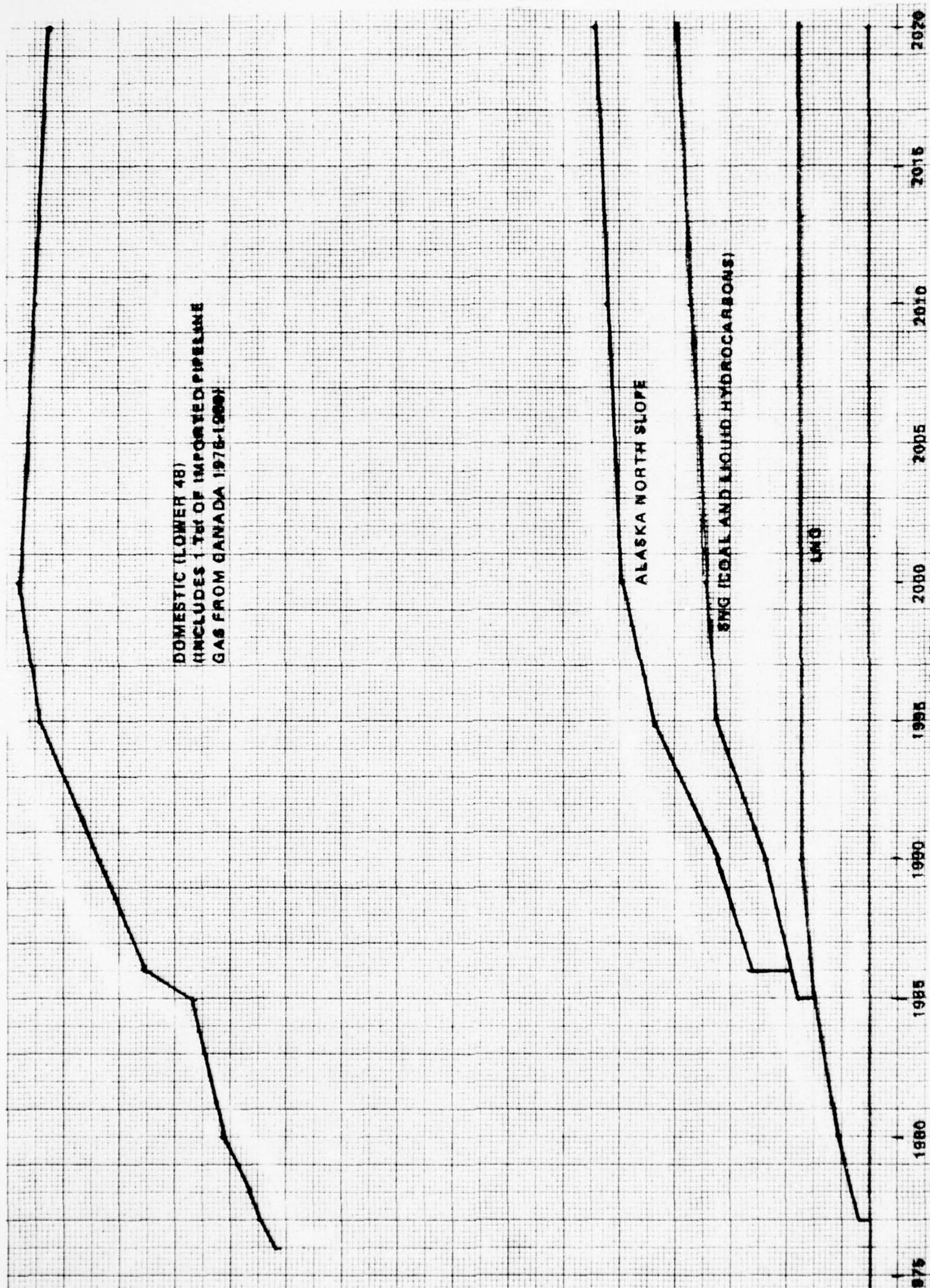

FIGURE 14. Projected Aggregate Supply.

TABLE 40. Total Cost and Supply Summary.

Source	1977	1980	1985	1986	1990	1995	2000	2010	2020
Lower 48									
Amount (Tcf/yr)	20.52	21.00	21.80	21.90	22.00	21.80	21.50	20.50	19.00
Percent of total	93.6	89.9	89.4	83.8	79.3	73.0	70.2	68.3	64.4
Cost (75 dollars/Mcf)	1.75	1.90	2.13	2.20	2.45	2.80	3.12	3.25	3.25
Alaska									
Amount (Tcf/yr)				1.5	1.8	2.4	3.0	3.0	3.0
Percent of total				5.7	6.5	8.0	9.8	10.0	10.2
Cost (75 dollars/Mcf)				3.00	3.00	3.00	3.00	3.00	3.00
SNG-L									
Amount (Tcf/yr)		0.28	0.23	0.22	0.18	0.15	0.12		
Percent of total		1.2	0.9	0.8	0.6	0.5	0.4		
Cost (75 dollars/Mcf)		4.00	4.50	4.60	5.00	5.50	6.00		
SNG-C									
Amount (Tcf/yr)			0.35	0.40	1.25	3.00	3.50	4.00	5.00
Percent of total			1.4	1.5	4.5	10.1	11.4	13.3	16.9
Cost (75 dollars/Mcf)			4.10	4.15	3.40	3.45	3.50	3.65	3.80
LNG									
Amount (Tcf/yr)	0.4	1.07	2.00	2.12	2.50	2.50	2.50	2.50	2.50
Percent of total	1.8	4.6	8.2	8.1	9.0	8.4	8.2	8.3	8.5
Cost (75 dollars/Mcf)	3.00	3.50	3.90	3.98	4.10	4.30	4.50	4.70	4.90
Pipeline imports									
Amount (Tcf/yr)	1.00	1.00							
Percent of total	4.6	4.3							
Cost (75 dollars/Mcf)	1.94	2.50							
Total Amount (Tcf/yr)	21.92	23.35	24.38	26.14	27.73	29.85	30.62	30.00	29.50
Weighted average									
Cost (75 dollars/Mcf)	1.78	2.02	2.32	2.44	2.54	3.02	3.28	3.40	3.46

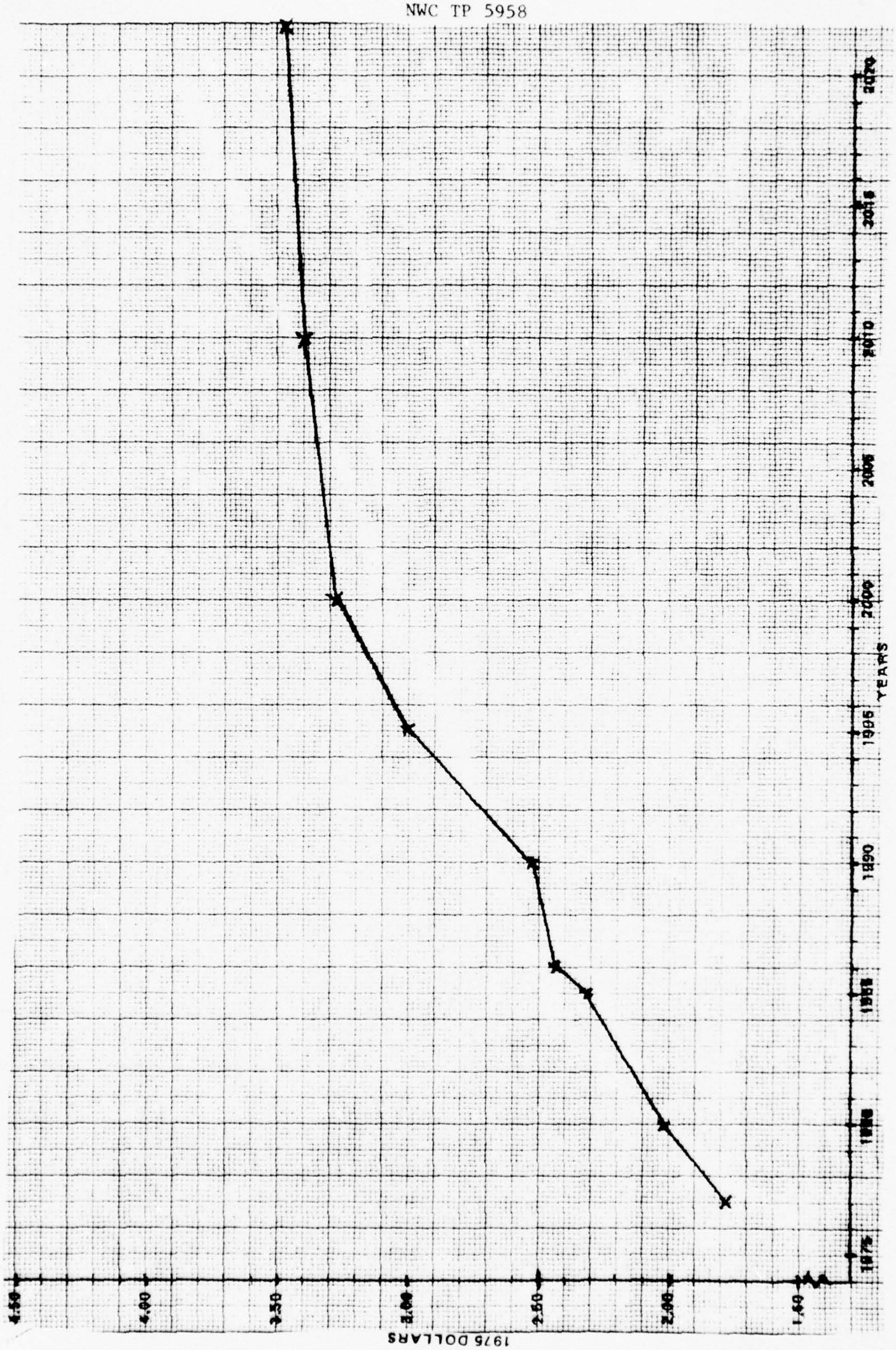

FIGURE 15. Projected Aggregate (Weighted Average) Well-Head Cost.

If a number of these contingencies occur, the price of natural gas probably would still rise to the average intrastate well-head price (currently $1.55/Mcf), continue to rise as exploration and technology are stimulated, to about $1.75/Mcf in 1980. Rising reserves and increased production would cause the price to stabilize and remain at this level through 2020.

Pessimistic Estimate

The following future events, if they occurred, would lead to higher natural gas costs.

- In bid for energy self-sufficiency and failure to exploit its new finds, Canada stops exporting pipeline gas to the United States.
- LNG technology lags.
- OPEC continues to escalate well-head price of natural gas (which would be exported as LNG).
- Canada does not approve trans-Canada pipeline from Prudhoe fields; gas must be shipped as LNG from Alaska south coast to West Coast at a considerably higher cost than anticipated.
- Deregulation does not stimulate exploration as expected and/or new finds considerably below past 10-year average, leading to a steady diminishing of reserves and R/P ratio.
- SNG-C technology lags, cost estimate on Lurgi process too low, accompanied by coal costs rising more rapidly than anticipated.
- Advanced fracturing techniques prove uneconomical and impractical.
- Litigations tie up exploration on the Atlantic's outer continental shelf.
- No pipeline gas from Mexico.

If a number of these contingencies occur, the price of natural gas would still rise to the average intrastate well-head price and continue to rise, reaching $2.40 in 1985 (Ref. 25). Under severe conditions, it is speculated that the projected year-end gas reserves would be 90.16 Tcf in 1990 (Ref. 16). The pessimistic conditions assumed here are even worse. Consequently, the supply of natural gas would be expended by 1995, or before, and there would be inadequate alternate gas sources to fill the void. From 1985 to 1995, the cost would continue to rise because of the scarcity of the commodity. The results of the three cases, optimistic, pessimistic, and most probable are displayed in Figure 16.

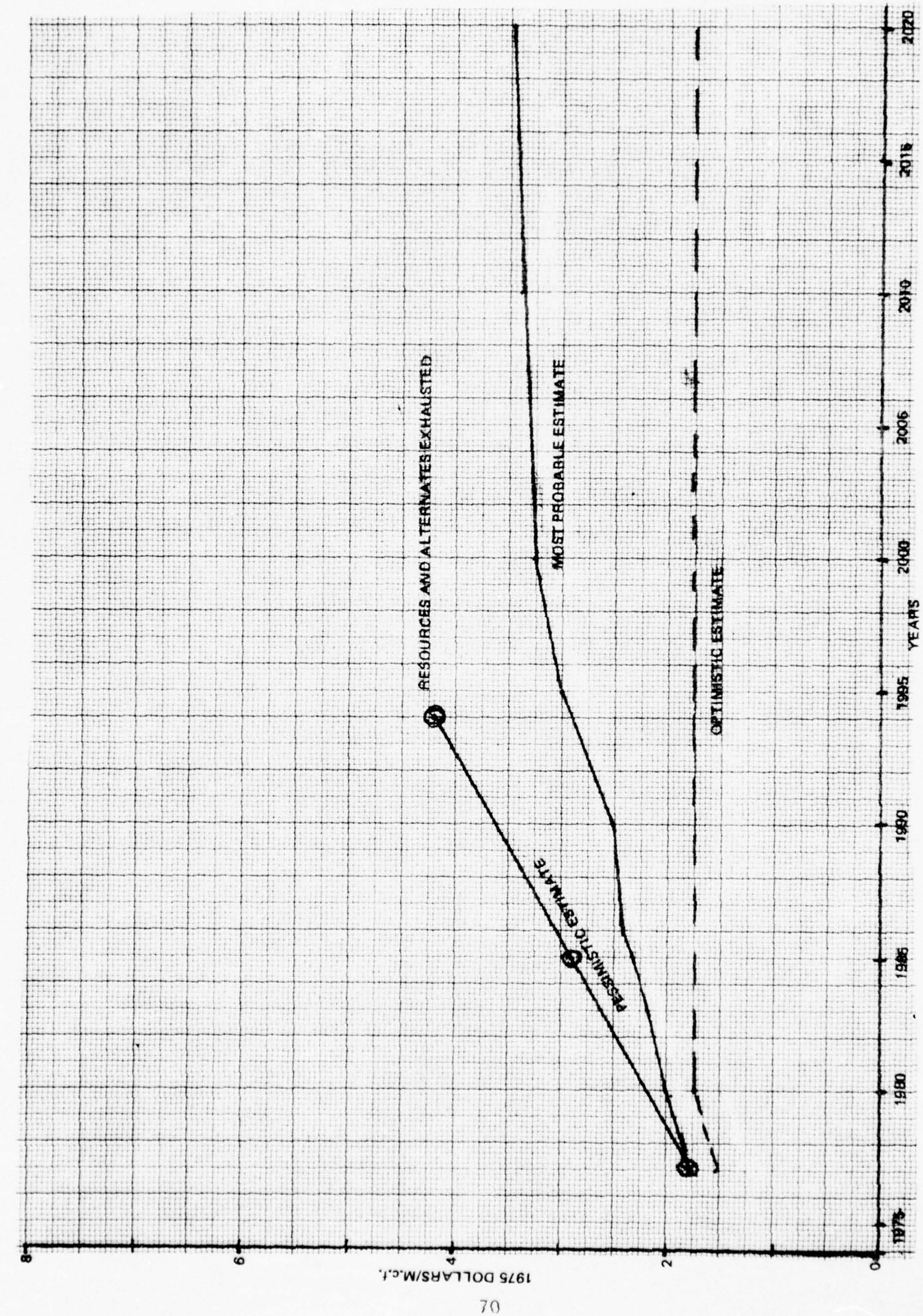

FIGURE 16. Projected Aggregate Well-Head Cost of Natural Gas.

SUMMARY

The price of natural gas will increase as the price of new gas is deregulated and, in all likelihood, will continue to rise. Reserves will probably increase for a short period, then level off, and gradually decline. Production and supply will follow the same pattern. Considering the inexorable increase in overall demand and the establishment of end-use priorities, the Navy should consider sources other than natural gas to meet its energy requirements.

PETROLEUM

INTRODUCTION

Domestic petroleum production will continue to supply less of the United States demand which should increase about 1% per year between now and the year 2020. This is illustrated in Table 41 (reference 17) which shows the United States and World consumption versus proven reserves at the time of the oil embargo.

The share of imports is shown in Table 42 (reference 17) and total demand is shown in Figure 17.

The political climate for the oil importer today produces highly uncertain world oil prices (reference 42). Economic pressures on many major oil exporters are minimal because greater revenues are not needed to support their economic growth. World oil prices are currently far above production costs of the key suppliers in the Middle East who have 60% of the world reserves. Foreign sources of oil and their prices are likely to be quite unpredictable through 1985. The development of domestic substitutes in the United States will be costly, requiring revenue for the product approaching or exceeding current world crude prices at $11 per barrel. With such foreign leverage on world oil prices the United States will be forced to subsidize in one form or another the development of domestic substitutes.

Figure 18 (reference 42) shows the complete cycle of United States petroleum production based on three different estimates of reserves.

TABLE 41. Petroleum Reserves and Rate of Consumption (1972).

	United States	World
Consumption	6.03×10^9 barrels/yr	19.6×10^9 barrels/yr
Proven reserves	38×10^9 barrels	633×10^9 barrels

TABLE 42. The Share of Imports in United States Domestic Petroleum Demand. (thousands of barrels)

	U.S. IMPORTS			DOMESTIC DEMAND FOR REFINED PRODUCTS			IMPORTS
Year	Total	Daily Average	% Change	Total	Daily Average	% Change	as a % of Demand
1947	159,389	437	–	1,989,803	5,452	–	8.0%
1948	188,144	514	+17.6%	2,113,678	5,775	+ 5.9%	8.9
1949	235,559	645	+25.5	2,118,250	5,803	+ 0.5	11.1
1950	310,261	850	+31.8	2,392,974	6,556	+13.0	13.0
1951	308,191	844	– 0.7	2,578,766	7,065	+ 7.8	11.9
1952	348,507	952	+12.8	2,668,134	7,290	+ 3.2	13.1
1953	377,409	1,034	+ 8.6	2,776,778	7,608	+ 4.4	13.6
1954	383,9[illegible]	1,052	+ 1.7	2,833,896	7,764	+ 2.1	13.5
1955	455,564	1,248	+18.6	3,088,348	8,461	+ 9.0	14.7
1956	525,891	1,436	+15.1	3,214,651	8,783	+ 3.8	16.3
1957	574,589	1,574	+ 9.6	3,221,949	8,827	+ 0.5	17.8
1958	620,589	1,700	+ 8.0	3,327,993	9,118	+ 3.3	18.6
1959	649,[illegible]	1,780	+ 4.7	3,477,173	9,527	+ 4.5	18.7
1960	664,111	1,815	+ 2.0	3,585,920	9,797	+ 2.8	18.5
1961	[illegible]	1,917	+ 5.6	3,641,280	9,976	+ 1.8	19.2
1962	759,753	2,082	+ 8.6	3,796,039	10,400	+ 4.3	20.0
1963	774,713	2,123	+ 2.0	3,921,364	10,743	+ 3.3	19.8
1964	826,736	2,259	+ 6.4	4,034,236	11,023	+ 2.6	20.5
1965	900,772	2,468	+ 9.3	4,202,039	11,512	+ 4.4	21.4
1966	939,162	2,573	+ 4.3	4,410,799	12,084	+ 5.0	21.3
1967	925,991	2,537	– 1.4	4,594,526	12,590	+ 3.9	20.2
1968	1,039,360	2,840	+11.9	4,901,789	13,393	+ 6.6	21.2
1969	1,155,561	3,166	+11.5	5,159,930	14,137	+ 5.6	22.4
1970	1,248,062	3,419	+ 8.0	5,364,473	14,697	+ 4.0	23.3
1971	1,432,990	3,926	+14.8	5,552,560	15,212	+ 3.5	25.8
1972	1,735,314	4,741	+20.8	5,990,316	16,367	+ 7.6	29.0
1973	2,283,495	6,256	+32.0	6,317,203	17,308	+ 5.7	36.1
1974[p/]	2,222,179	6,088	– 2.7	6,069,471	16,629	– 3.9	36.6

p/ Preliminary

FIGURE 17. United States Demand for All Oils.

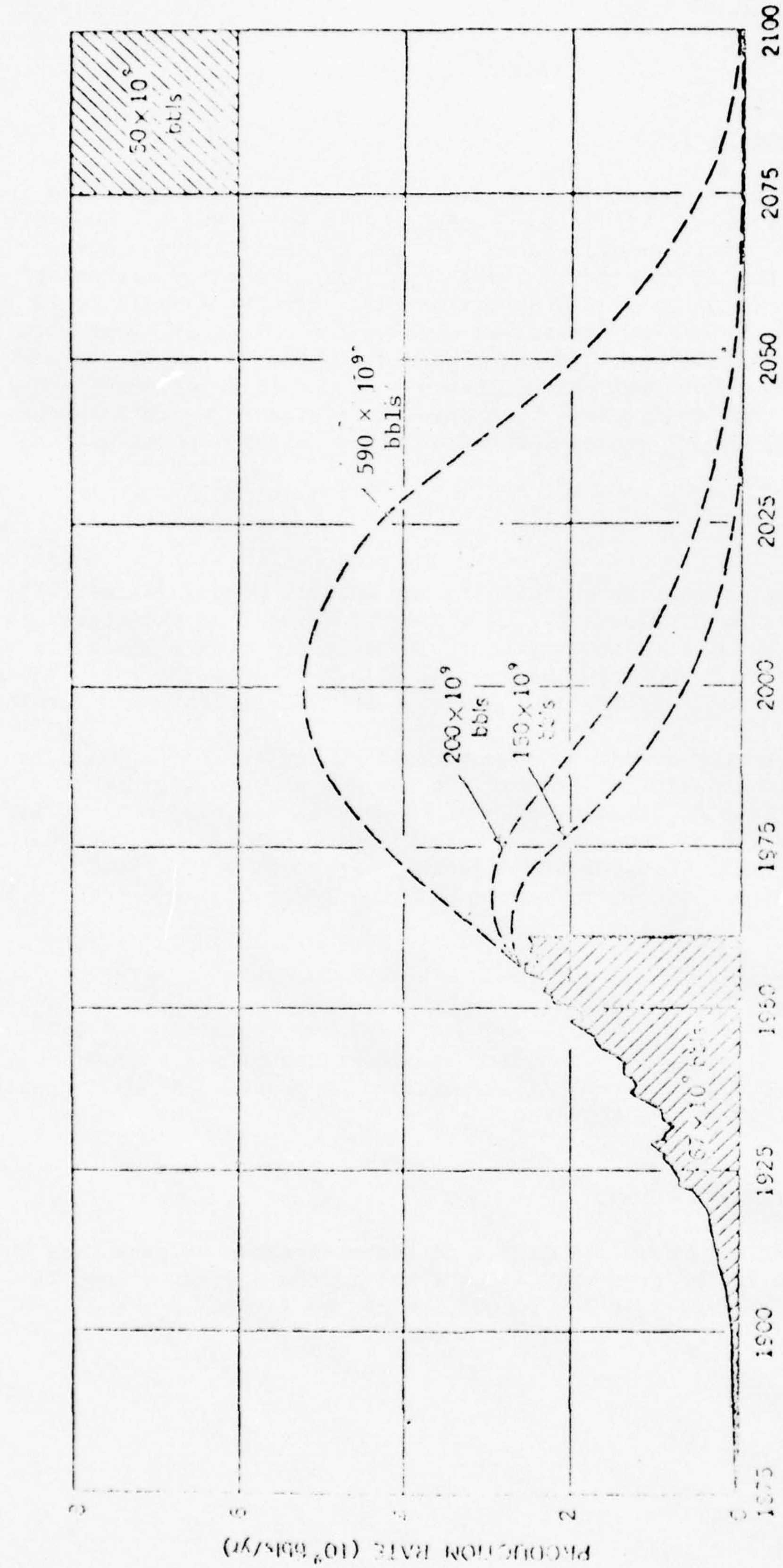

FIGURE 18. Comparison of Complete Cycles of United States Crude-Oil Production Based Upon Estimates of 150-200 and 590 Billion Barrels for Estimated Reserves.

THE EVOLVING SUPPLY PICTURE

Early in the development of an oil or gas field the finding rates are characteristically high. Within three years after World War II, domestic petroleum was plentiful. A much lower cost source of oil then became available in the Middle East in the 1950s. Drilling activity logically followed the high finding rates overseas so that over the last 10 to 15 years drilling in the United States has declined at a rate of about 4 to 5% per year. Production costs in the Middle East were so low that crude oil could be delivered to the United States more cheaply, including transportation costs, than could crude from domestic fields. To protect domestic oil producers, oil import quotas were established in 1959 and maintained until 1973.

OIL FROM SHALE

There are vast resources of shale in the western United States. The Green River Formation of Eocene age in western Colorado, northeastern Utah, and southwestern Wyoming, a total area of about 16,000 square miles, is estimated to contain $1,800 \times 10^9$ barrels of oil (Ref. 42). Of this, 139×10^9 barrels are of sufficiently high grade to warrant present consideration.

There are a number of extraction processes under consideration. In one for an assumed capacity of 10^5 barrels per day of synthetic crude oil production, two mines of capacity 62,500 tons/day each would be required. The shale is retorted at temperatures above 1,100°F which, in addition to releasing the kerogen, forms highly alkaline by-product waste (Ref. 42). The water requirements are estimated to be 8,000 to 16,000 acre-feet (3.5 to $7.0 \times 10^8\ ft^3$) per year.

The above capacity would not support a very large fraction of present crude consumption. If ten such plans were operated, the production rate would be 1 million barrels per day but would involve the mining of 1.25 million tons of oil shale per day which is almost the present annual coal production of the United States. However, in situ processing could greatly reduce the amount of mining required.

ELASTICITY OF PETROLEUM DEMAND

Elasticity of demand is the degree of responsiveness of consumers to a price change in the product. It is equal to the percent change in quantity demanded, divided by the percentage change in demand.

$$E_d = \frac{\Delta Q / Q}{\Delta P / P} \qquad (1)$$

In equation (1), Q is the quantity demanded and P is the price.

A high degree of elasticity ($E_d >> 1$) is favorable to the consumer and a low value ($E_d << 1$) is unfavorable to the consumer. When $E_d = 1$ the situation is neutral; the supplier neither makes nor loses money by raising his price. When elasticity is higher, the consumer is in control and the supplier loses money if he raises his prices. When E_d is low, the supplier can raise his prices and, consequently, his profits, and the consumer response will not thwart him.

Elasticity is apparently very low in the case of fossil fuels in both fact and theory. For instance, gasoline consumption recently declined only the order of 10% in the face of 100% price increases at the pump. This represents an elasticity of approximately 0.1.

In theory, the elasticity of demand of a product is greater (1) the larger the number of good substitutes that are available; (2) the larger the item is with respect to one's total budget; and (3) the more the product is regarded as a luxury item. At present, fossil fuels fail all three tests and the low value of elasticity, therefore, should not be surprising.

Attempts to use price-demand elasticity information to assist in predicting the future price of petroleum were not successful. There appears to be little useful data on price-demand elasticity relationships for energy.

PETROLEUM PRICES

Available reports hesitate to predict the price of petroleum fuels beyond 1985. This is because the period 1985-1990 is expected to begin a new epoch for the several reasons shown in Table 43.

TABLE 43. Epoch Events of 1985-1990.
(Optimistic and not necessarily in order of importance)

1. Alaska pipeline reaches full production.
2. Extraction of shale oil reaches significant production levels.
3. Production of synthetic fuel from coal and solid wastes becomes a reality.
4. Nuclear plants significantly relieve demand on fossil fuels for the generation of electricity.
5. Conservation measures (e.g., better insulated homes, carpools, mass transit) reduce the demand for petroleum products.
6. Alternative sources (mostly geothermal) relieve energy demand by the order of 1%. Solar energy and other sources under full development.

If most of the events in Table 43 become true, it is quite possible that the price of petroleum products after 1985 will not increase in real dollars. The optimistic curve in Figure 19, therefore, shows petroleum prices, specifically for number 2 diesel, increasing at 6% faster than inflation between 1975 and 1985 (after Hoffman-Muntner report, reference 43) and level with inflation after 1985. Number 2 diesel was chosen because this fuel and the similarly priced heating fuel oil are the principal products used by the Navy.

It is also possible to take the view that most of these events fail as shown in Table 44.

TABLE 44. Epoch Events of 1985-1990.
(Pessimistic and not necessarily in order of importance)

1. Pipeline fails to reach full production, costs of operation become excessive, reserves in Alaska and rest of world not as large as thought.
2. Shale oil technology ''bombs out.''
3. Synthetic fuel technology not cost effective, especially in removing sulfur and other toxic constituents.
4. Safety and waste disposal problems reduce neclear-generating capacity.
5. Conservation measures ignored.
6. Alternative energy sources not developed.

If most of the events in Table 44 occur, the price may continue to increase at the worst rate predicted by reference 3 until 2020. That is, prices will increase 8% faster than inflation between 1975 and 2020.

A more probable curve (Figure 19) can be constructed by taking the mean of the optimistic and pessimistic. The increase is 7% until 1985 and reduced to 4% after 1985.

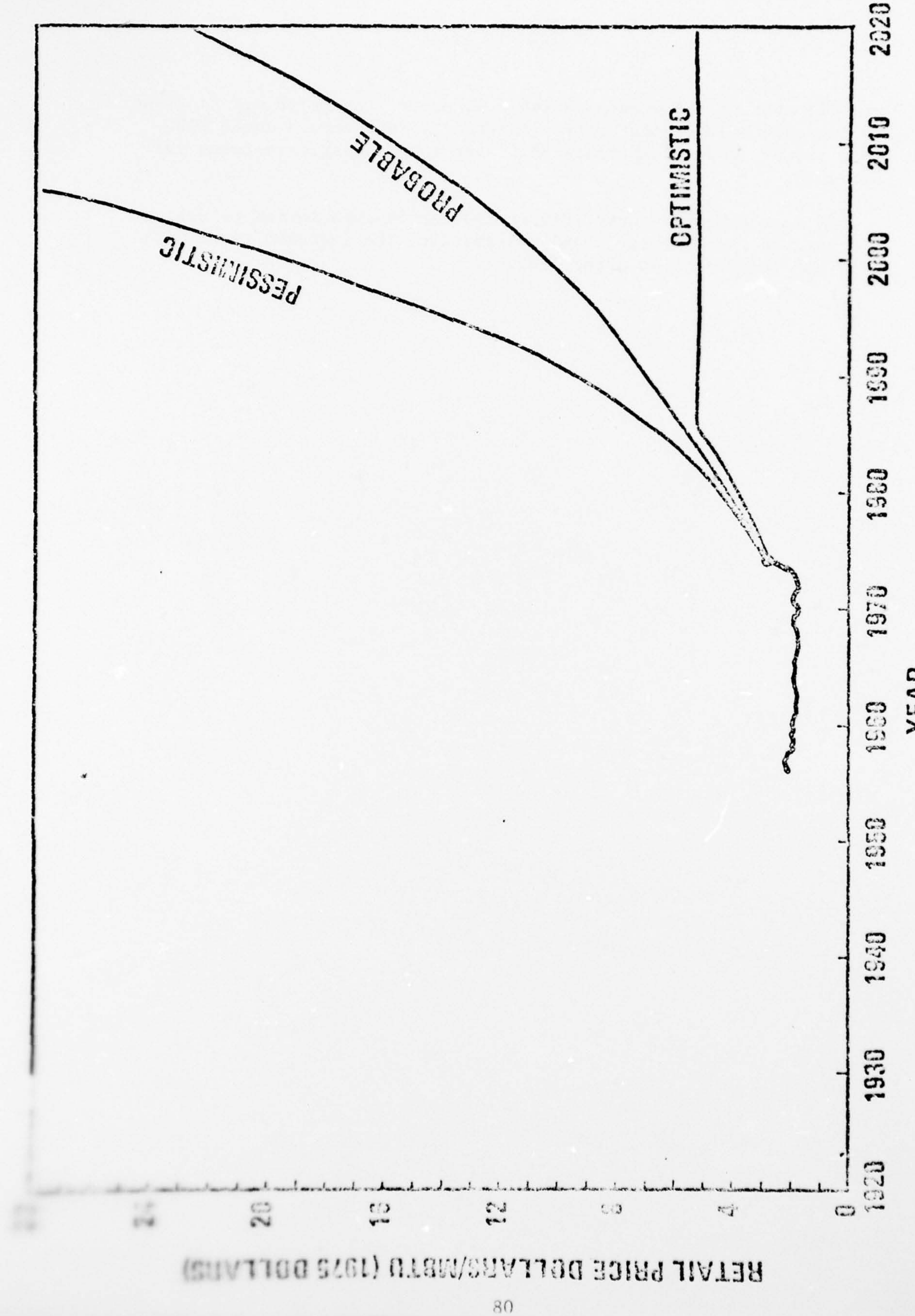

FIGURE 19. Retail Price Projections for Diesel Number 2.

ELECTRICITY

INTRODUCTION

The economics of power generation and the evaluation of alternatives from the standpoint of cost is a complex undertaking. There are many factors which must be considered. Some of these include energy resource costs of plant facilities, power transmission costs, interest rate, value of the dollar, and the effects of escalation and economic changes.

Economic forecasting methods can be grouped into two categories, extrapolation and correlation. Extrapolation is based upon the assumption that future growth will be a continuation of discernible patterns of past growth. The results are acceptable because electric loads show stable growth over long periods of time. Of course, underlying changes which affect future growth are considered. Some of these changes might be the availability of the raw materials used in the production of electricity and the quantity of the electricity demanded by the populous due to unusual weather conditions, e.g., air conditioning and/or heating.

Correlation relates electrical power loads to selected associated factors. These factors include the availability of the fuels used to generate the power and the current and projected cost.

In order to be knowledgeable in the economics of future power generation, a few topics must be understood. These include the history of the industry, the potential future of electrical utilization, cost of fuels for electricity in the past-present-future and cost predictions in the future.

These subjects follow, along with tables and curves to substantiate the data.

From its small beginnings at Edison's steam electric station in New York City, the electric industry has experienced rapid growth and development. In the early 1880s, local groups built electric power plants to provide energy for the immediate area.

The introduction of the transformer in 1886 led to the rise of alternating current, higher distribution voltages, and an expansion of the servicing area by an individual plant. The increasing economics of scale in power production and the standardization of equipment led to many consolidations of the small electric companies serving given areas. The diminution of competition led to government regulation of public utilities and government ownership as a means to try to achieve lower rates for local consumers.

The electrical utility industry in the United States is dominated by a rapid expansion in energy output. Between 1948 and 1973, the energy output increased from 300×10^6 megawatthour (MWhr) to 2000×10^6 MWhr. The annual growth rate has averaged over 8%. If this continues, the output should be 3200×10^6 MWhr in 1980 and 6200×10^6 MWhr in 1990 (reference 44).

FUELS FOR ELECTRICITY

Energy sources most commonly used for the generation of electricity in the United States are coal, oil, gas, and falling water. Nuclear fuel is being utilized more and more and it is projected that by the end of the century will make up more than half the nation's electrical energy needs (see Figures 20, 21, 22, reference 44).

Coal is the most abundant indigenous fossil fuel and provides the primary energy for about 56% of fossil-fueled electric generation. The major attraction of the use of coal by the electric industry is its relative abundance and price stability despite inflation.

Nearly 18% of the natural gas consumed in the country is burned to generate electricity in utility power plants. The consumption of natural gas by electric utilities is expected to decline rapidly in the future to 16.3% in 1880 and to 3.8% in the year 2000 (reference 44). Projections of the consumption of gas are shown in Table 45 (reference 45).

The advent and large scale use of nuclear energy is probably the most important single change in the electric power industry during the past fifty years. It is estimated that nuclear capacity will constitute 21% of the total electric generating capacity in 1980 and 38% in 1990.

Electric power cost projections are provided on a regional basis which is the same used by both the Federal Power Commission and the National Coal Association to provide an effective cost projection. Population in conjunction with electrical energy trends are considered. It is estimated that each customer will use three times as much electricity in 1990. Other factors which must be considered are the projected retirements of the generating unit, e.g., 30 years for thermal units, availability and cost of sites for expansion and new plants, e.g., nuclear fuel plants, transportation, e.g., equipment and product, and export-import across state and national boundaries. The actual selling price per kilowatthour of electricity will be a function of fuel cost, plus all other costs.

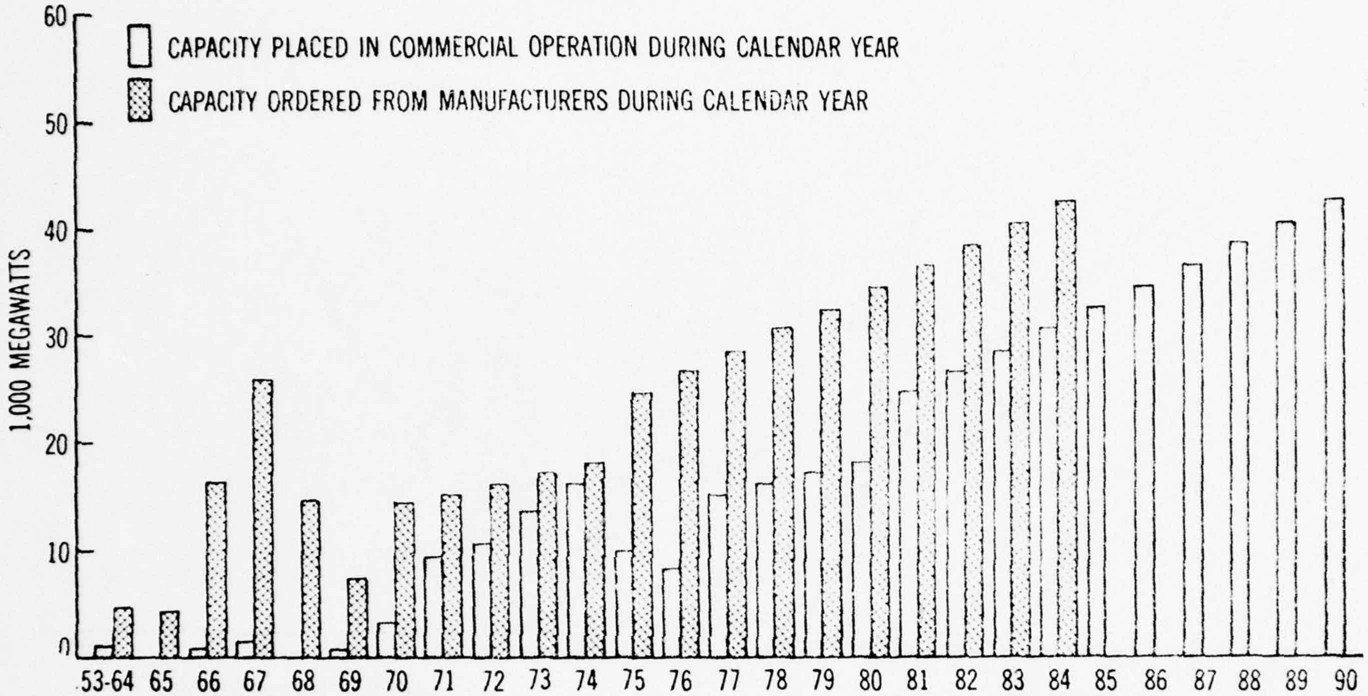

FIGURE 20. Nuclear Electric Capacity.
Existing and Projected
December 31, 1970

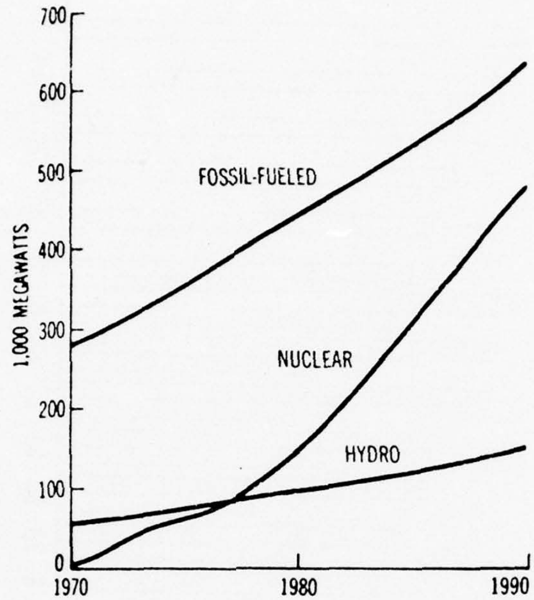

FIGURE 21. Projected Nuclear, Hydro and Fossil-Fueled Capacity.

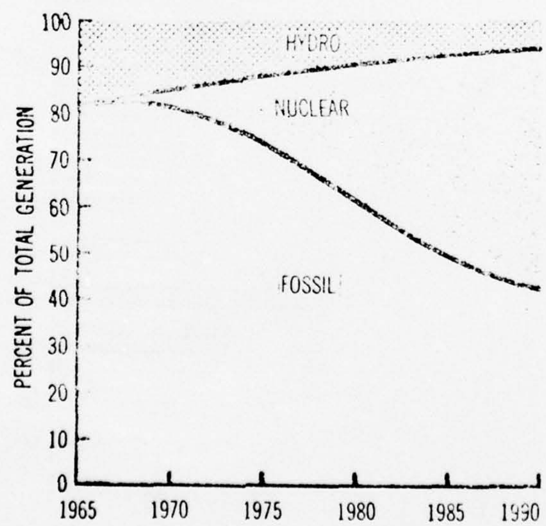

FIGURE 22. Projected Generation Mix.

TABLE 45. Fossil Fuel Inputs to the Electrical Sector 1974 and Projected to the Year 2000.

	1974	1980	1985	2000
Coal				
Million short tons	390.6	547	704	941
Trillion Btu	8,668	12,250	15,700	20,700
Percent of total 1/	56.1	63.3	67.1	78.4
Natural Gas				
Billion cubic feet	3,260	1,940	1,460	970
Trillion Btu	3,328	2,000	1,500	1,000
Percent of total 1/	21.5	10.3	6.4	3.8
Petroleum				
Million barrels	554	830	1,000	750
Trillion Btu	3,448	5,100	6,200	4,700
Percent of total 1/	22.4	26.4	26.5	17.8
Total				
Trillion Btu	15,444	19,350	23,400	26,400

p/ Preliminary.
1/ Percentages may not add to 100 due to independent rounding. Based on Btu input.

The forecast of power requirements for the South Central Region should peak out at a compound growth rate at 6.9% around 1990 based on population growth estimates. The compound growth rate for the West Central Region in population is 1.4% by 1990. Therefore, the power requirements should be around 6.5% compound growth rate.

The compound growth rate for the West Region in energy requirements is 7.3%. It is interesting to note that this region, having the highest growth rate, also expects to have an increase in nuclear power to compensate for the need.

The Northeast Region should have a compound growth rate of 4.5% to the year 1990. This region also imports power from Canada. It is interesting to note that the Southeast and the East Central Regions are about the same as the South Central Region (see Figure 23, reference 44).

COST

It is obvious from studying the charts of estimated annual electric utility generation by primary energy sources and estimated annual fossil fuel requirements for electric utility generation that the price of coal will be one of the most important factors in the price of electricity (Figures 24, 25 and 26, reference 44).

A list and plot of the cost in cents/KWhr from 1926 through 1975 (reference 46) is shown in Figure 27 and Table 46. The cost has been corrected to 1975 dollars. The estimated cost of electricity from an optimistic, probable, and pessimistic standpoint from the year 1976 through 2020 is added to the plot (Figure 27) and Table 46. It is noted that the optimistic cost growth rate is 1%, probable is 3%, and pessimistic is 6%. These prices reflect the projected costs of the fuels needed to generate electrical power.

Also included in the price prediction is the consideration that the demand for electricity is growing faster than that for any other form of energy. An increase in efficiency is expected in conventional fossil fueled plants, and even greater gains are expected with advanced cycle plants and breeder reactors. There will also be an increase in the use of coal and a decrease in the use of natural gas and petroleum. The conversion of existing plants will contribute to the increase in electricity prices. Tables 47 through 50 are forecasts given in this study (reference 45). Table 47 shows the installed generating capacity and the projected generating capacity. Table 48 shows that nuclear plants will be the major power source in the future and petroleum will be used much less. Table 49 is an overall survey of the situation.

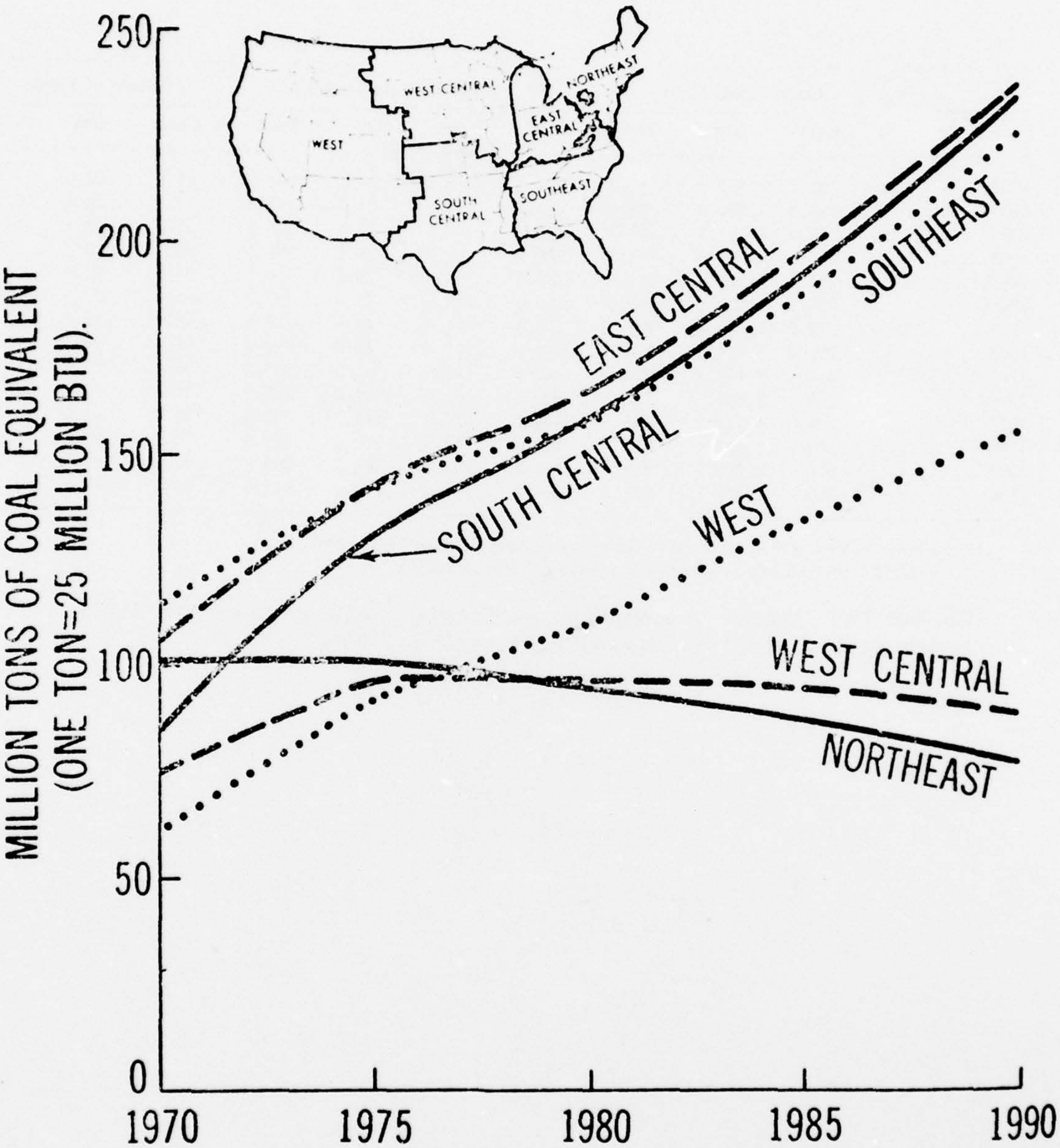

FIGURE 23. Projected Fossil Fuel Requirements for Electric Power Generation by Regions.

Year	Conventional Units [1]			10^6 Tons of Coal Equivalent [2]				Percent of Total		
	Coal	Gas	Oil	Coal	Gas	Oil	Total	Coal	Gas	Oil
1961	182.1	1,825.1	85.7	174.8	76.3	21.6	272.7	64.1	28.0	7.9
1962	193.2	1,966.0	85.8	185.4	82.3	21.7	289.4	64.1	28.4	7.5
1963	211.3	2,144.5	93.3	202.6	89.6	23.5	315.7	64.2	28.4	7.4
1964	225.4	2,322.9	101.1	215.7	97.0	25.6	338.3	63.7	28.7	7.6
1965	244.8	2,321.1	115.2	233.5	97.0	29.0	359.5	64.9	27.0	8.1
1966	266.5	2,609.9	140.9	253.0	109.2	35.5	397.7	63.6	27.5	8.9
1967	274.2	2,746.4	161.3	258.3	114.7	40.6	413.6	62.5	27.7	9.8
1968	297.8	3,147.9	188.6	280.5	131.4	47.5	459.4	61.1	28.6	10.3
1969	310.3	3,486.4	250.9	292.3	145.5	63.2	501.0	58.4	29.0	12.6
1970	322	3,894	332	300.2	161.7	82.8	544.7	55.1	29.7	15.2
1975	425	4,110	565	396.1	170.2	141.2	707.5	56.0	24.0	20.0
1980	500	3,800	640	464.0	157.3	160.0	781.3	59.4	20.1	20.5
1985	600	3,800	725	554.4	157.3	181.3	893.0	62.1	17.6	20.3
1990	700	4,200	800	644.0	174.0	200.0	1,018.0	63.3	17.1	19.6

[1] In millions of tons of coal, millions of barrels of oil, and millions Mcf of gas.

[2] A ton of coal equivalent was assumed as containing 25 million Btu.

FIGURE 24. Annual Consumption of Fossil Fuels by Electric Utility Power Plants, 1961-1970, and Projected to 1990.

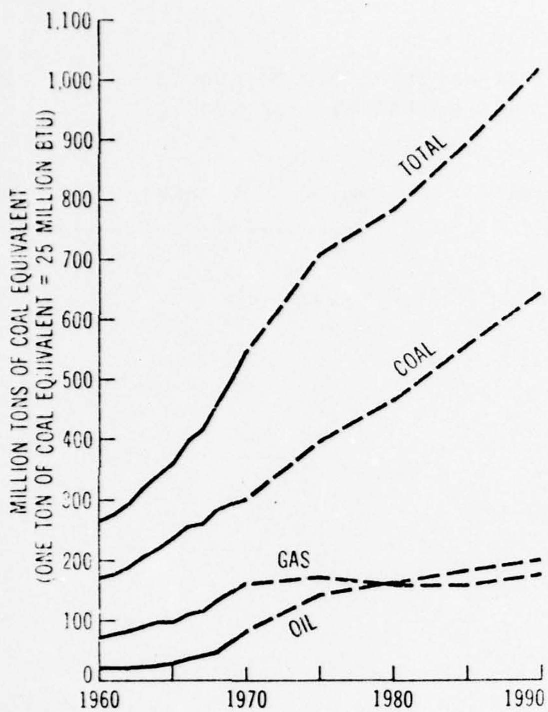

FIGURE 25. Estimated Annual Fossil Fuel Requirements for Electric Utility Generation.

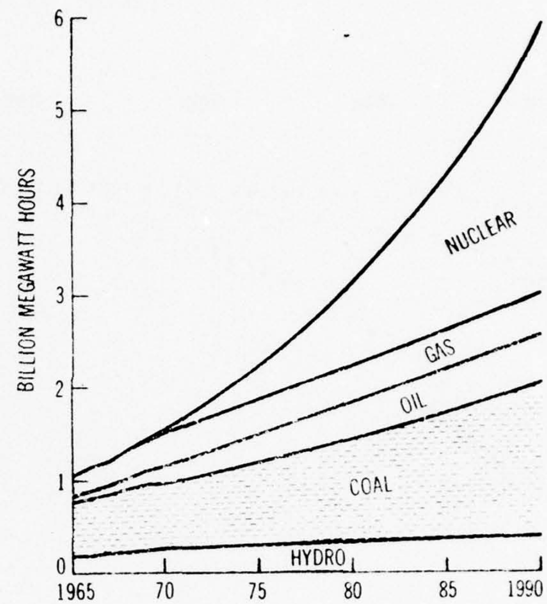

FIGURE 26. Estimated Annual Electric Utility Generation by Primary Energy Sources.

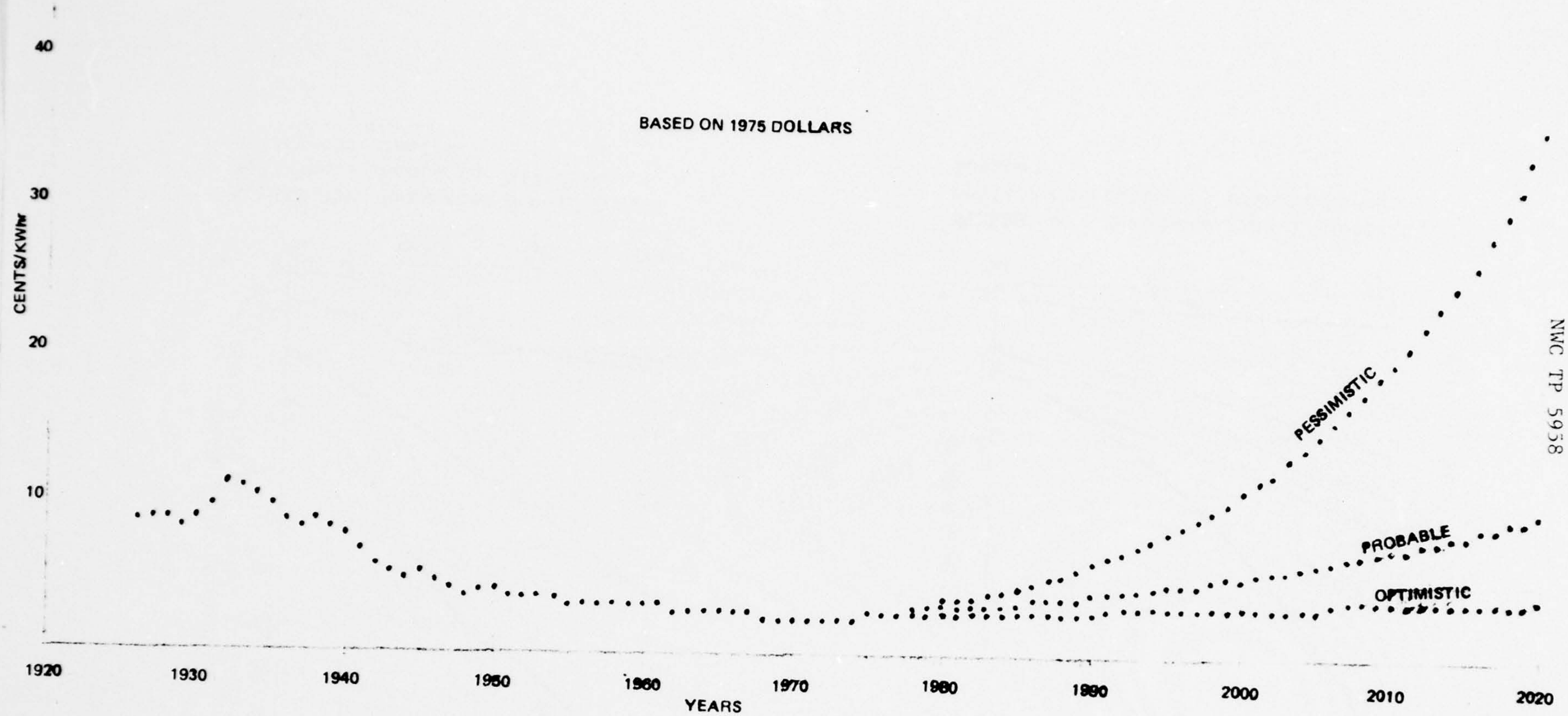

FIGURE 27. Estimated Cost of Electricity from an Optimistic, Probable, and Pessimistic Standpoint.

TABLE 46. Historical Electricity Costs Corrected to 1975 Dollars.

Year	Cents/KWhr	Year	Cents/KWhr
1926	8.16	1951	3.67
1927	8.29	1952	3.62
1928	8.24	1953	3.53
1929	7.97	1954	3.50
1930	8.46	1955	3.34
1931	9.63	1956	3.23
1932	11.09	1957	3.17
1933	10.93	1958	3.18
1934	10.25	1959	3.11
1935	9.53	1960	3.04
1936	8.70	1961	3.03
1937	8.02	1962	2.79
1938	8.68	1963	2.87
1939	8.27	1964	2.80
1940	7.80	1965	2.70
1941	6.85	1966	2.58
1942	5.84	1967	2.50
1943	5.10	1968	2.39
1944	4.98	1969	2.21
1945	5.11	1970	2.16
1946	4.94	1971	2.22
1947	4.21	1972	2.21
1948	3.97	1973	2.22
1949	4.17	1974	2.46
1950	4.02	1975	2.57

Year	Optimistic cost growth rate 1%	Probable cost growth rate 3%	Pessimistic cost growth rate 6%
1976	2.60	2.64	2.72
1977	2.62	2.73	2.89
1978	2.65	2.81	3.06
1979	2.67	2.89	3.24
1980	2.70	2.98	3.44
1981	2.73	3.07	3.65
1982	2.76	3.16	3.86
1983	2.78	3.26	4.10
1984	2.81	3.35	4.34
1985	2.84	3.46	4.60

TABLE 46. (Contd.)

Year	Optimistic cost growth rate 1%	Probable cost growth rate 3%	Pessimistic cost growth rate 6%
1986	2.87	3.56	4.88
1987	2.90	3.67	5.17
1988	2.92	3.78	5.48
1989	2.96	3.89	5.81
1990	2.98	4.01	6.16
1991	3.01	4.13	6.53
1992	3.04	4.25	6.92
1993	3.07	4.38	7.34
1994	3.10	4.51	7.78
1995	3.14	4.64	8.24
1996	3.17	4.78	8.74
1997	3.20	4.92	9.26
1998	3.23	5.07	9.82
1999	3.26	5.23	10.41
2000	3.29	5.38	11.03
2001	3.33	5.54	11.69
2002	3.36	5.71	12.39
2003	3.40	5.88	13.13
2004	3.43	6.06	13.92
2005	3.46	6.24	14.76
2006	3.50	6.43	15.65
2007	3.53	6.62	16.58
2008	3.57	6.82	17.58
2009	3.60	7.02	18.64
2010	3.64	7.23	19.75
2011	3.68	7.45	20.94
2012	3.71	7.68	22.19
2013	3.75	7.91	23.53
2014	3.79	8.14	24.94
2015	3.83	8.39	26.43
2016	3.86	8.64	28.02
2017	3.90	8.90	29.71
2018	3.94	9.16	31.48
2019	3.98	9.44	33.37
2020	4.02	9.72	35.38

TABLE 47. Electric Utility Industry-Installed Generating Capacity, Net Generation and Thermal Equivalent Resource Inputs, 1974 Preliminary, and Projected to the Year 2000.

Year	Installed Generating Capacity (MW)	Apparent Capacity Factor	Net Generation (Billion kW-hr)	Heat Rate (Btu/kW-hr)	Energy Resource Inputs (Trillion/Btu)
1974p					
Fuel burning plants	379,744	0.44	1,466	10,535	15,444
Nuclear plants	31,662	0.39	110	10,660	1,173
Hydropower & geothermal	63,168	0.53	291	10,389	3,018
	474,574	0.45	1,867	10,517	19,635
1980					
Fuel burning plants	484,000	0.46	1,950	9,930	19,350
Nuclear plants	75,000	0.65	427	10,660	4,550
Hydropower plants 3/	88,000	0.50	385	9,500	3,650
Geothermal plants	1,000	0.80	7	21,690	150
	648,000	0.49	2,769	10,000	27,700
1985					
Fuel burning plants	603,000	0.46	2,430	9,640	23,400
Nuclear plants	200,000	0.65	1,139	10,400	11,840
Hydropower plants 3/	94,000	0.45	370	9,200	3,400
Geothermal plants	3,000	0.80	21	21,690	450
	900,000	0.50	3,960	9,870	39,090
2000					
Fuel burning plants	824,000	0.41	2,960	8,930	26,400
Nuclear plants	900,000	0.65	5,085	9,060	46,08[illegible]
Hydropower plants 3/	153,000	0.40	535	8,500	4.550
Geothermal plants	10,000	0.80	70	21,690	1,520
	1,887,000	52.3	8,650	9,080	78,550

1/ Fuel burning plants include steam, internal combustion, and gas turbine plants. Heat rate based on energy inputs to all fuel burning plants.
2/ Includes all types.
3/ Includes pumped storage.

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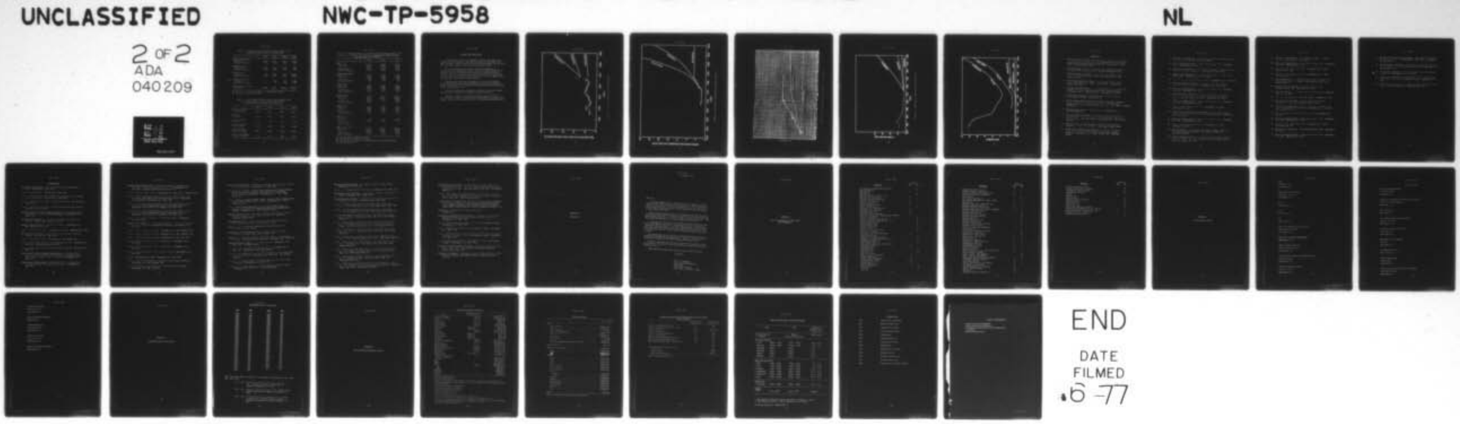

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TABLE 48. Conversion Losses for the Electrical Sector, 1974 Preliminary and Projected to the Year 2000.

	1974	1980	1985	2000
Fossil fueled plants				
Trillion Btu	10,442	12,700	15,110	16,320
Percent of total 1/	78.7	69.6	59.0	33.3
Hydropower plants				
Trillion Btu	2,025	2,340	2,140	2,720
Percent of total 1/	15.3	12.8	8.4	5.5
Nuclear plants				
Trillion Btu	798	3,090	7,950	28,710
Percent of total 1/	6.0	16.9	31.1	58.6
Geothermal plants 2/				
Trillion Btu	--	120	380	1,280
Percent of total 1/	--	.7	1.5	2.6
Total Conversion Losses				
Trillion Btu	13,265	18,250	25,580	49,030

1/ Percentages may not add to 100 due to independent rounding.
2/ Included in hydropower for 1974.

TABLE 49. United States Electric Utility Power Statistics (on Population, Capacity, and Consumption Basis) 1974 Preliminary and Projected to the Year 2000.

	1974	1980	1985	2000
Generating capacity (Thousand MW)	474.6	648.0	900.0	1,887.0
Population (Millions)	211.9	224.1	235.7	264.4
Kilowatt capacity per capita	2.2	2.9	3.8	7.1
Power consumption (Billion kWh)	1,867	2,769	3,960	8,650
Annual per capita consumption (kWh)	8,811	12,356	16,800	32,715
Nuclear power capacity (Percent of total)	6.7	11.6	22.2	47.7

TABLE 50. Comparative Analysis of Electrical Sector Energy Inputs, 1975-2000, for the 1972 and 1975 Versions of United States Energy Through the Year 2000 (Trillion Btu).

	1980	1985	2000
Coal			
1972 Study	10,660	14,220	17,520
1975 Study	12,250	15,700	20,700
Difference 1/	-1,590	-1,480	-3,180
Percent decline 1/	-14.9	-10.4	-18.2
Liquid Hydrocarbons			
1972 Study	5,000	6,650	5,040
1975 Study	5,100	6,200	4,700
Difference 1/	-100	450	340
Percent decline 1/	-2.0	6.8	6.8
Gaseous Fuels			
1972 Study	3,600	3,450	2,640
1975 Study	2,000	1,500	1,000
Difference 1/	1,600	1,950	1,640
Percent decline 1/	44.4	56.5	62.1
Nuclear Energy			
1972 Study	6,720	11,750	49,230
1975 Study	4,550	11,840	46,080
Difference 1/	2,170	-90	3,150
Percent decline 1/	32.3	.7	6.4
Hydropower 2/			
1972 Study	3,990	4,320	5,950
1975 Study	3,650	3,400	4,550
Difference 1/	340	920	1,400
Percent decline 1/	8.5	21.3	23.5
Geothermal 3/			
1972 Study	-	-	-
1975 Study	150	450	1,520
Difference 1/	-	-	-
Percent decline 1/	-	-	-
Total Energy Inputs			
1972 Study	29,970	40,390	80,380
1975 Study	27,700	39,090	78,550
Difference 1/	2,270	1,300	1,830
Percent decline 1/	7.6	3.2	2.3

1/ Negative figure indicates increase.
2/ 1972 version included pumped storage.
3/ Not specifically broken out in 1972 version of United States Energy Through the Year 2000.

SUMMARY AND CONCLUSIONS

The price that the Navy is expected to pay for coal, fuel oil, natural gas, and electricity have been estimated for the period 1975-2020. Included in these projections are the price extremes that may occur for each energy source as well as the most probable price.

The price estimates were based on available literature, on discussions with knowledgeable people, and on historical trends where possible. Much of the literature was found to be repetitive and to contain little or no original work. The biases inherent in the literature were taken into account as much as possible. It is recognized that by doing this, other biases were introduced.

Governmental action (laws, embargos, etc.) both in the United States and in other countries are expected to have a major effect on future energy prices. It is difficult to predict what these actions will be and when they will occur.

The price projections as presented, therefore, are based on facts where possible but must be considered subjective in nature.

The price estimates are repeated in Figures 28, 29, 30 and 31 for convenience. Figure 32 contains the price estimates for each of the energy sources for the probable case on a dollars-per-million-Btu basis.

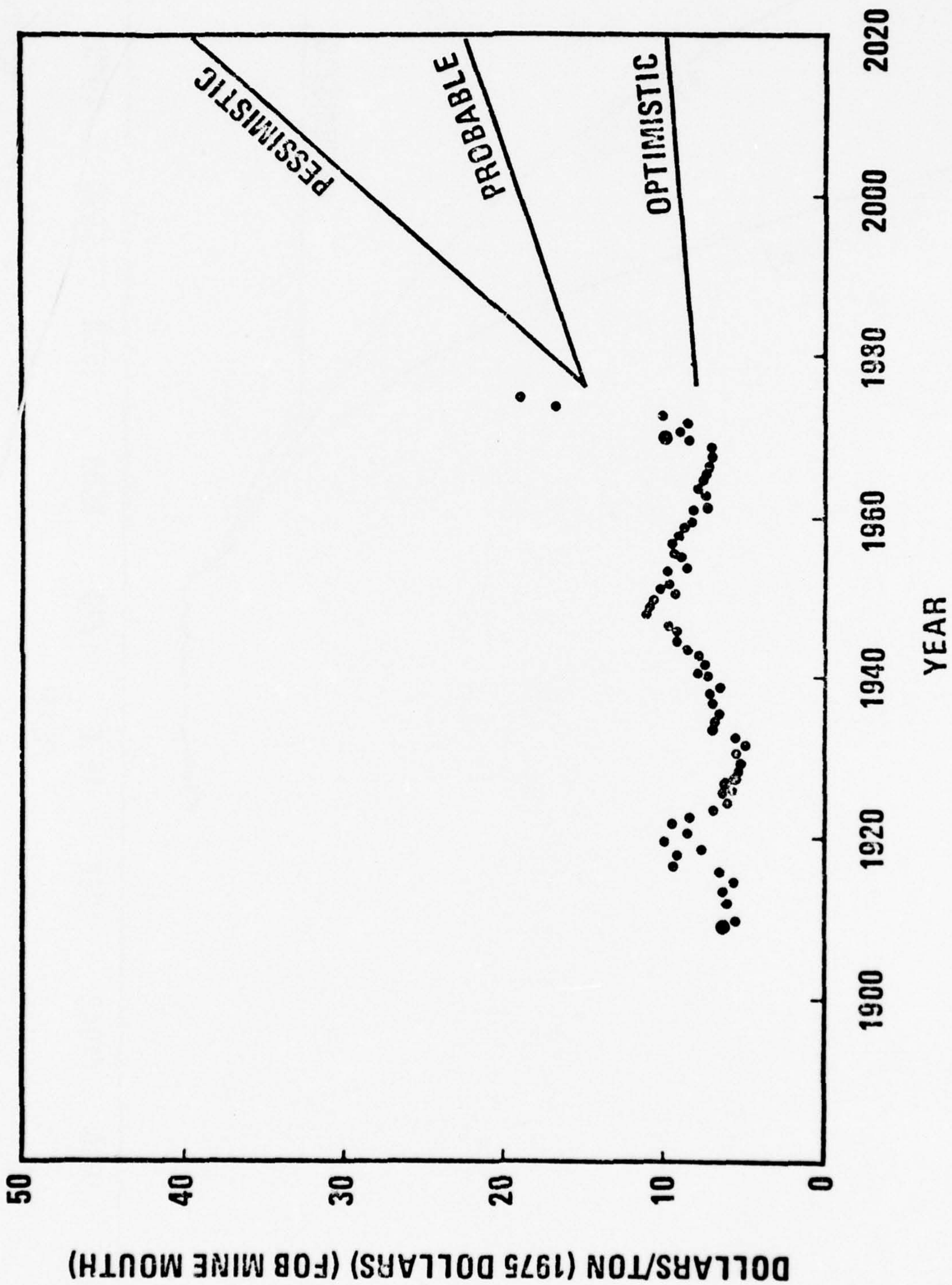

FIGURE 28. Coal Price Projections, FOB Mine Mouth.

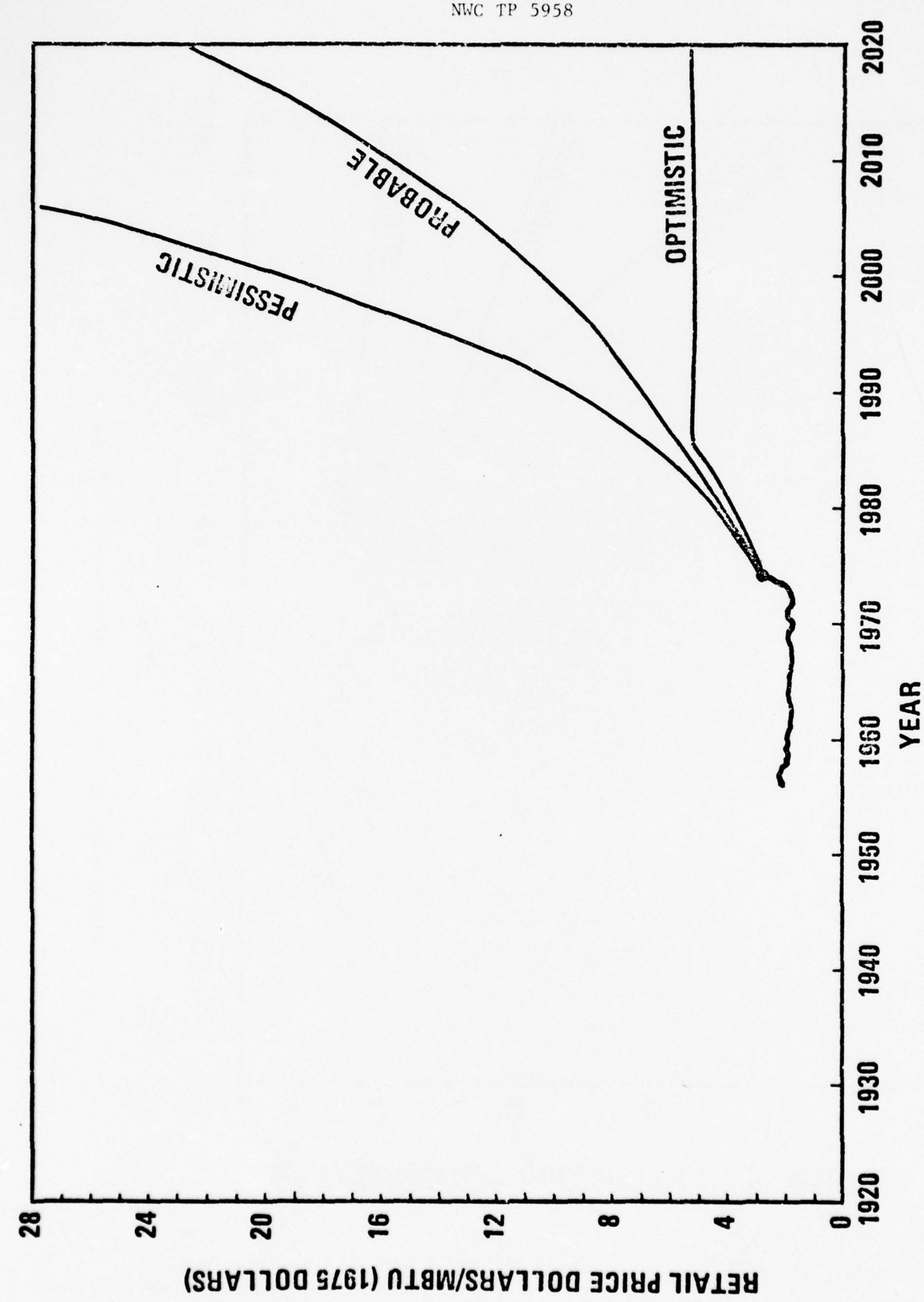

FIGURE 29. Retail Price Projections for Diesel Number 2.

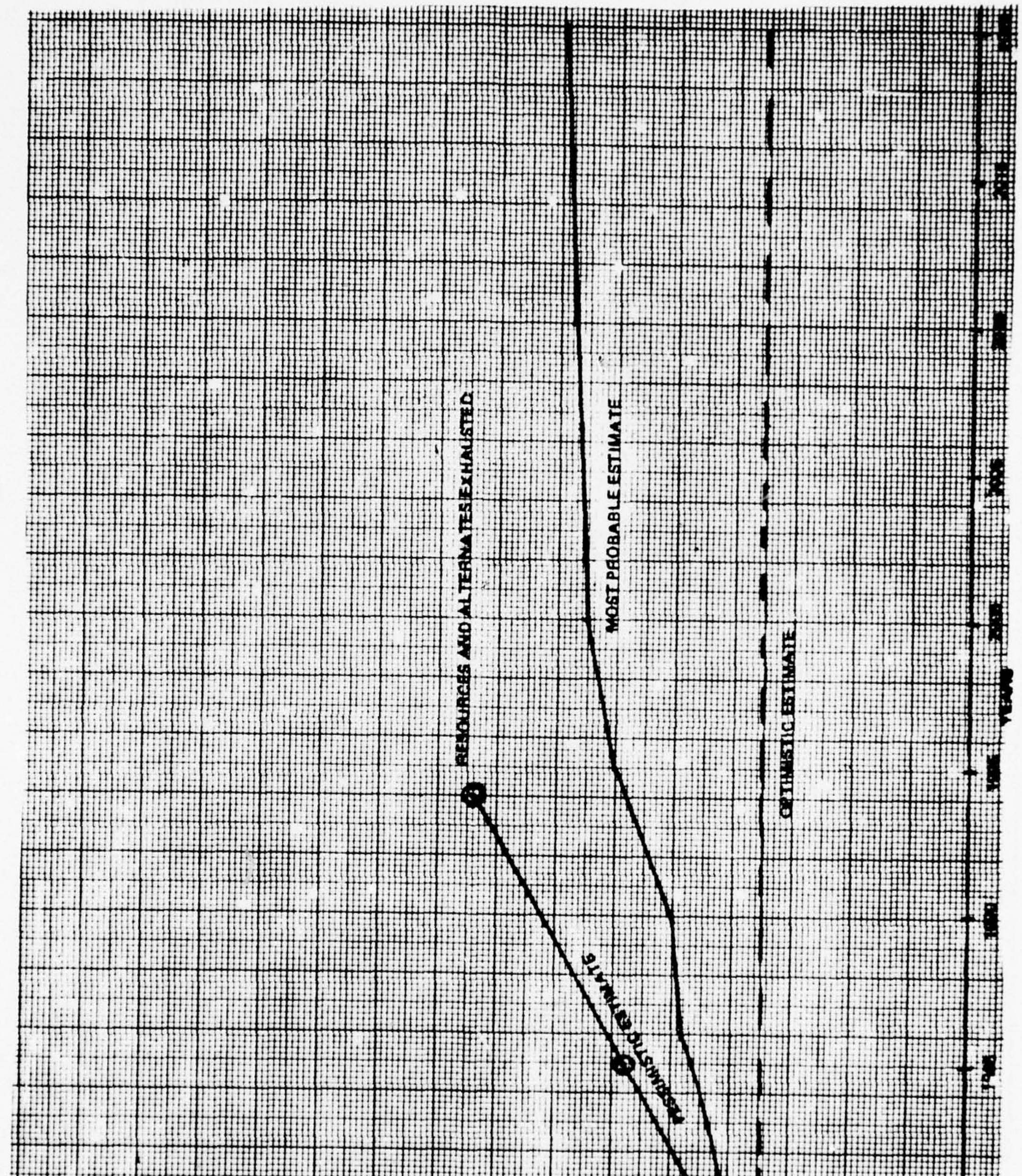

FIGURE 30. Projected Aggregate Well-Head Cost of Natural Gas.

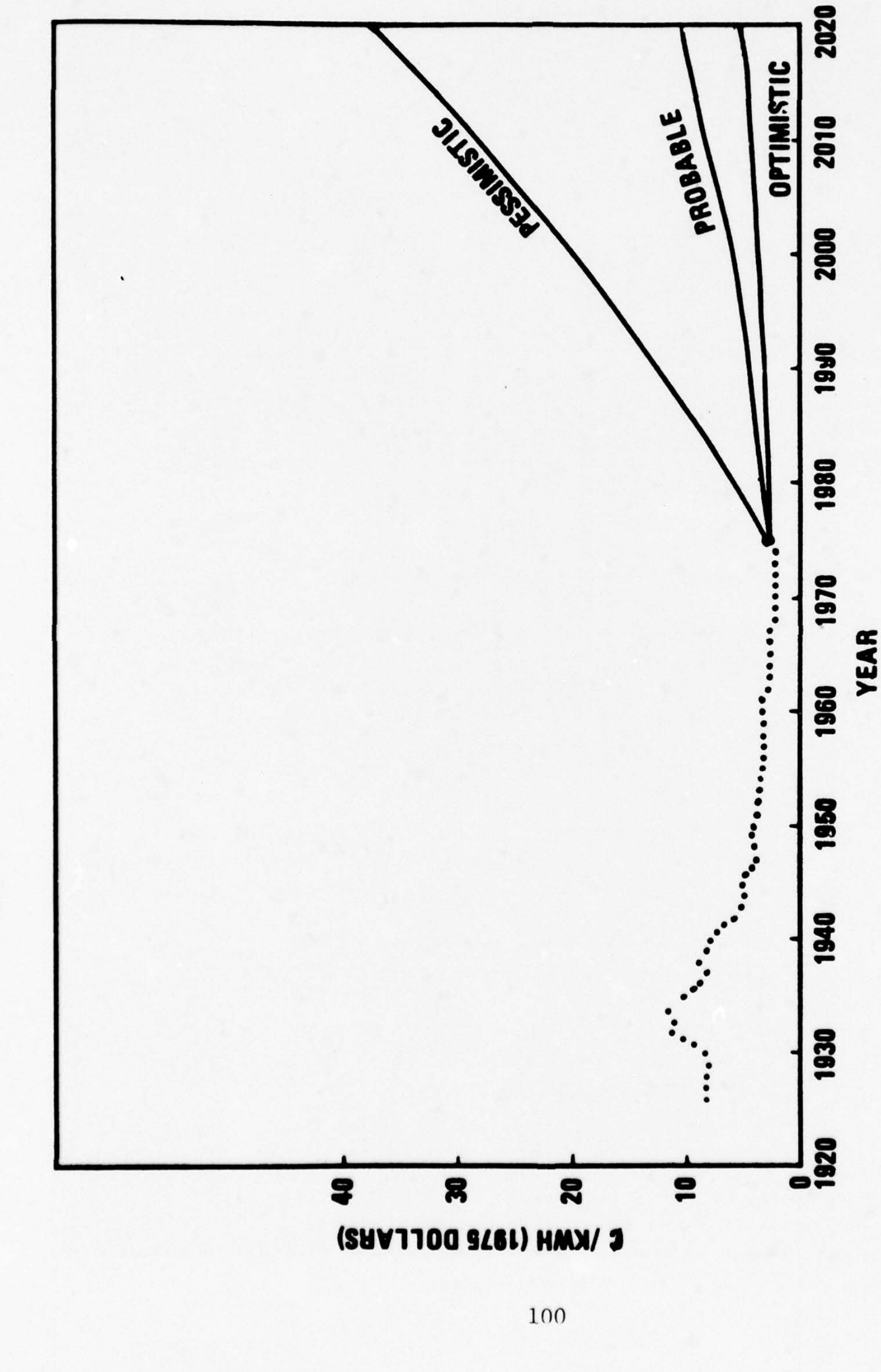

FIGURE 31. Retail Price Projections for Electricity.

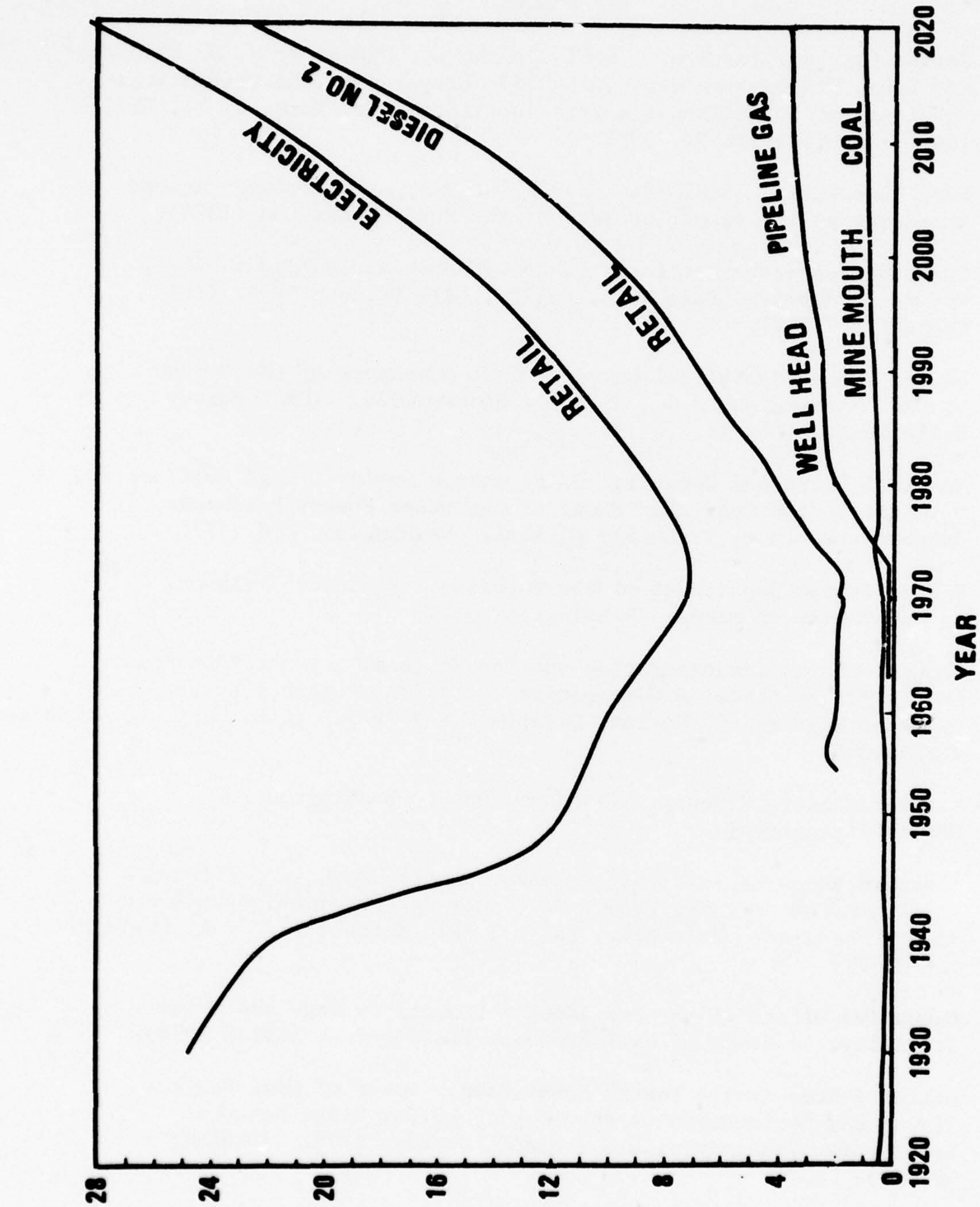

FIGURE 32. Energy Price Projections

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APPENDIX A

FORM LETTER

28 January 1976

Dear Sir:

The Naval Weapons Center, China Lake has been asked to conduct studies of fuel and energy availability and cost. These studies are sponsored by the Naval Facilities Engineering Command. They are for the purpose of ensuring adequate future supplies of fuel and energy at Naval Shore Facilities.

One of these studies requires us to document the historical production, use, and cost of natural gas, fuel oil, coal, and electricity and to make projections as to their future availability and cost. The time period of interest is from about 1900 to the year 2020.

We are writing to several selected corporations, government agencies, and industry associations requesting assistance in obtaining information for our studies. It seems probable that in depth studies have been conducted detailing both past and projected usage and cost of natural gas, fuel oil, coal, and electricity by organizations such as yours.

Any assistance you can provide in identifying and obtaining such information would be greatly appreciated. Copies of reports or information as to where we can obtain them would be most useful.

We will cite credit to any material furnished or withhold credit as you desire. Any material that you identify as proprietary will be treated as such.

Thank you for any assistance that you may be able to provide.

Sincerely,

ELLIS E. KAPPELMAN
Asst. for Systems Analysis
Code 45402
Naval Weapons Center
China Lake, California 93555

APPENDIX B

LIST OF ADDRESSEES OF FORM LETTER AND RESPONDENTS

Addressee	Response Yes	Response No
Air Transport Association of America		X
Alabama Power Co.		X
Amax Coal Co.	X	
Amerada Hess		X
American Electric Power Co., Inc.		X
American Gas Association	X	
American Petroleum Institute		X
Atlantic City Electric	X	
Atlantic Richfield	X	
Atomic Industrial Forum	X	
Aztec Oil and Gas Co.		X
Baltimore Gas & Electric Co.	X	
Bituminous Coal Research	X	
Brooklyn Union Gas	X	
Carolina Power & Light Co.	X	
Center for Strategic & International Studies	X	
Central & Southwest		X
Central Illinois Public Service		X
Central Louisianna Electric Co., Inc.		X
Central Maine Power		X
Chase Manhattan Bank		X
Chicago Electric Co.		X
Cities Service Co.		X
Citizens Gas & Coke Utility		X
Clark Oil & Refining		X
Cleveland Electric Illuminating	X	
Coal Research, Inc.	X	
Columbia Gas System of Ohio		X
Columbus & Southern Ohio Electric		X
Commonwealth Edison Co.		X
Consolidated Coal Co.		X
Consolidated Edison Co. of New York		X
Consumers Power Co.	X	
Continental Oil	X	
Detroit Edison		X
Duke Power Co.		X
East Ohio Gas Co.		X
Edison Electric Institute	X	
Energy Institute		X
Federal Power Commission	X	
Florida Power & Light	X	
Gas Service Co.	X	
General American Oil	X	
Georgia Power Co.		X
Getty Oil		X
Gulf Oil		X

Addressee	Response Yes	Response No
Hawaiian Electric Co., Inc.	X	
Houston Lighting & Power Co.		X
Interstate Natural Gas Association	X	
Jacksonville Electric Authority	X	
Lone Star Gas		X
Long Island Lighting Co.		X
Los Angeles Department of Water & Power	X	
Marathon Oil		X
Memphis Light, Gas & Water Division	X	
Michigan Consolidated Gas Co.		X
Nashville Electric Power Board	X	
National Association of Electric Companies	X	
National Coal Association		X
National Fuel Gas Co.		X
National Oil Fuel Institute		X
National Petroleum Council		X
Nevada Power Co.		X
Niagara Mohawk Power Co.		X
Northern Illinois Gas	X	
Northern Indiana Public Service		X
Northern States Power Co.		X
Office of Technology Assessment	X	
Ohio Edison Co.		X
Oil and Gas Association, Western		X
Oklahoma Gas & Electric		X
Omaha Public Power District		X
Pacific Gas & Electric Co.	X	
Peabody Coal Co.		X
Penn Power & Light Co.		X
Peoples Gas, Light & Coke Co.	X	
Philadelphia Electric		X
Philadelphia Gas Works	X	
Phillips Petroleum		X
Pittston Coal Co.	X	
Power Authority of the State of New York	X	
Public Service, Indiana		X
Public Service, New Hampshire		X
Public Service, New Jersey		X
Puerto Rico Water Resources Authority		X
Sacramento Municipal Utility	X	
Salt River Project	X	
San Antonio Public Service Board		X
San Diego Gas & Electric	X	
Seattle Department of Lighting	X	
Seattle Electric Works	X	
Shell Oil	X	
Southern California Edison Co.	X	

Addressee	Response Yes	Response No
Southern California Gas Co.		X
Southern Indiana Gas & Electric		X
Southwestern Public Service		X
Standard Oil of Ohio		X
Sun Oil	X	
Superior Oil		X
Tampa Electric		X
Tennessee Valley Authority		X
Texas Utilities		X
Union Electric Co.		X
United Gas, Inc.		X
United Mine Workers of America		X
United States Department of the Interior	X	
Utilities Research Associations, Inc.		X
Virginia Electric & Power Co.	X	
Washington Natural Gas Co.		X

APPENDIX C

LIST OF PLACES VISITED

ERDA
#20 Mass. Ave
Washington, D.C.

Resources for the Future
1755 Mass. Ave. N.W.
Washington, D.C.

Rand
Santa Monica, CA

EPRI
Palo Alto, CA

SRI
Menlo Park, CA

Council on Wage and Price Stability
726 Jackson Place N.W.
Washington, D.C.

Americans for Energy Independence
Washington, D.C.

Federal Power Commission
825 N. Capital St. N.E.
Washington, D.C.

National Rural Electric Cooperative Assoc.
2000 Florida Ave
Washington, D.C.

National Petroleum Council
1625 K St. N.W.
Washington, D.C.

PLACES VISITED

American Gas Association
1515 Wilson Blvd.
Arlington, VA

Center for Strategic and International Studies
37 & 2 N.W (3520 Prospect)
Washington, D.C.

Dean Witter & Co.
Washington, D.C.

Air Transport Association of America
1709 N.Y. Ave N.W.
Washington, D.C.

Interstate National Gas Assoc.
1660 L St. N.W.
Washington, D.C.

Department of the Interior
18th & C
Washington, D.C.

US Geological Survey
Menlo Park, CA

Federal Energy Adm.
14th & Penn.
Washington, D.C.

National Association of Electric Companies
1140 Conn. Ave N.W.
Washington, D.C.

United Mine Workers
900 15th St. N.W.
Washington, D.C.

Booz-Allen Applied Research
Bethesda, MD

Hoffman-Munter Corp
8750 Georgia Ave
Washington, D.C.

National Coal Assoc.
1130 17th St N.W.
Washington, D.C.

American Petroleum Institute
Washington, D.C.

APPENDIX D

PURCHASING POWER OF THE DOLLAR

Purchasing Power of the Dollar

Year	PPD	Year	PPD
1913	537	1945	296
1914	530	1946	273
1915	524	1947	238
1916	415	1948	222
1917	415	1949	224
1918	353	1950	222
1919	307	1951	206
1920	265	1952	202
1921	298	1953	200
1922	317	1954	198
1923	312	1955	200
1924	311	1956	197
1925	303	1957	190
1926	301	1958	186
1927	306	1959	184
1928	310	1960	180
1929	310	1961	179
1930	318	1962	166
1931	350	1963	174
1932	389	1964	173
1933	411	1965	170
1934	397	1966	165
1935	387	1967	160
1936	383	1968	154
1937	370	1969	144
1938	377	1970	136
1939	383	1971	131
1940	379	1972	125
1941	361	1973	119
1942	326	1974	107
1943	307	1975	100
1944	302		

PPD = Purchasing Power of Dollar in cents based on 1975 dollars = 100. These were taken from:

1913 - 1957 *Historical Statistics of the U.S., Colonial to 1957*. Bureau of the Census, Department of Commerce, Washington, D.C. 1961.

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APPENDIX E

FUEL AND POWER CONVERSION FACTORS

Fuel and Power Conversion Factors

Fuel	Equivalent to 1 short ton of bituminous coal	Btu per unit
Bituminous – average[a]	1.000 tons	26,200,000 per ton
Pennsylvania anthracite	1.031 tons	25,400,000 per ton[j]
Lignite	1.58 tons	8,300 per lb
Brown coal	2.71 tons	4,830 per lb
Peat in the bog	6.96 tons	1,880 per lb
Crude petroleum	4.517 bbl	5,800,000 per bbl
Natural-gas liquids	6.532 bbl	4,011,000 per bbl
Natural gas	24,372 cu ft[b]	1,075 per cu ft[b]
Natural gas[d]	24,952 cu ft[e]	1,050 per cu ft[e]
Coke	1.056 tons[f]	24,800,000 per ton[f]
Coke breeze	1.248 tons[g]	21,000,000 per ton[g]
Blast-furnace gas	262,000 cu ft	100 per cu ft
Coke-oven gas	47,636 cu ft	550 per cu ft
Manufactured gas[d]	48,519 cu ft[c]	540 per cu ft[c]
Mixed gas[d]	28,887 cu ft[c]	907 per cu ft[c]
Tar and pitch	3.899 bbl	6,720,000 per bbl
Briquettes and packaged fuel	1.068 tons	28,000,000 per ton[k]
Kerosene	4.621 bbl	5,670,000 per bbl
Gasoline (natural)	–	4,620,000 per bbl
Gasoline (motor fuel)	5.021 bbl	5,218,080 per bbl
Gasoline (aviation)	5.190 bbl	5,048,400 per bbl
Distillate fuel oil; Diesel oil	4.498 bbl[h]	5,825,400 per bbl[h]
Residual fuel oil	4.167 bbl[i]	6,287,400 per bbl[i]
Acid sludge	5.822 bbl	4,500,000 per bbl
Refinery (still) gas	17,467 cu ft	1,500 per cu ft
Petroleum coke	0.870 tons	30,120,000 per ton
Coke oven and manufactured gas products, light oils	–	5,460,000 per bbl
Lubricants	–	6,060,000 per lb
Wax	–	5,570,000 per lb
Asphalt	–	6,640,000 per lb
Road oil	–	6,640,000 per lb
Wood	1.350 cords	19,407,407 per cord
Soft	–	5,820 per lb
Hard	–	5,820 per lb
Charcoal	–	12,100 per lb
Fuel alcohol	–	10,400 per lb
Farm waste	–	6,250 per lb
Dung[l]	–	7,500 per lb

[a] Includes all ranks of bituminous.

[b] At wellhead (containing liquids).

[c] Sold by utilities. Mixed gas includes a portion of natural gas, and this conversion factor applies to 1947 only.

[d] Gas is sometimes billed to the consumer by the "therm," which is 100,000 Btu, 262 therms is the equivalent of one ton of bituminous coal.

[e] As delivered to consumer (most liquids removed).

[f] Assuming 4 percent moisture as consumed.

[g] Assuming 12 percent moisture as consumed.

[h] Weighted average of grades 1 to 4.

[i] Weighted average of grades 5 and 6.

[j] Bureau of Mines, E.P. Carman, personal communication, May 2, 1951.

[k] La Ingenieria, Novembre-Decembre, 1948, Ano LII, No. 888, p. 532-535. Argentine publication.

[l] Based on Dr. R. E. Howe, formerly with U.S. Agricultural Research Center, Bureau of Animal Industry, Department of Agriculture, as worked up by H. C. Schor; personal communication, July 27, 1950.

Source: Putnam (see bibliography item 19).

Conversion Factors

	Btu	Per Unit
Coal:		
Anthracite (Penn.)	25,400,000	Ton
Bituminous	26,200,000	Ton
Blast Furnace Gas	100	Cu. Ft.
Briquettes and Package Fuels	28,000,000	Ton
Coke	24,800,000	Ton
Coke Breeze	20,000,000	Ton
Coke-Oven Gas	550	Cu. Ft.
Coal Tar	150,000	Gal.
Coke-Oven and Manufactured Gas Products, Light Oils	5,460,000	Bbl.
Natural Gas (Dry)	1,035	Cu. Ft.
Natural Gas Liquids (Average)	4,011,000	Bbl.
Butane	4,284,000	Bbl.
Propane	3,843,000	Bbl.
LNG		Btu/Bbl or Cu Ft
SNG		Btu/Bbl or Cu Ft
Petroleum:		
Asphalt	6,640,000	Bbl.
Coke	6,024,000	Bbl.
Crude Oil	5,800,000	Bbl.
Diesel	5,806,000	Bbl.
Distillate Fuel Oil	5,825,000	Bbl.
Gasoline, Aviation	5,048,000	Bbl.
Gasoline, Motor Fuel	5,253,000	Bbl.
Jet Fuel:		
Commercial	5,670,000	Bbl.
Military	5,355,000	Bbl.
Kerosene	5,670,000	Bbl.
Lubricants	6,060,000	Bbl.
Miscellaneous Oils	5,588,000	Bbl.
Refinery Still Gas	5,600,000	Bbl.
Heavy Fuel Oil	6,287,000	Bbl.
Road Oils	6,640,000	Bbl.
Wax	5,570,000	Bbl.
Electricity	3,412	Kwhr

Source: *Texas Eastern Gas Transmission* (see bibliography item 21).

Coefficients of Equivalence & Energy Contents for Various Fuels and for Electricity

	Coal Equivalent (Metric Tons)	Energy Content 10^3 Kilocalories
1 metric ton anthracite & bituminous coal	1	7,000
1 metric ton of coke of anthracite or bituminous coal	0.9	6,300
1 metric ton of lignite	0.3 to 0.6	2,100 to 4,200
1 metric ton of crude petroleum	1.3	9,100
1 metric ton of gasoline, kerosene, fuel oil	1.5	10,500
1000 cubic meters natural gas	1.33	9,310
1000 cubic meters manufactured and coke oven gases	0.6	4,200
1000 kilowatt-hour electrical energy – hydro	0.375	2,625
1000 kilowatt-hour electrical energy – thermal or nuclear	0.4	2,800
		Btu
The above energy contents are consistent with:		
1 pound of coal		12,600
1 pound of liquid fuel		18,000
1000 cubic feet of natural gas		1,050,000

Source: Felix (see bibliography item 15).

Heat and Electricity from Various Fuels

FUEL		HEAT	ELECTRICITY (assuming 33.3% conversion)
Engineering Units	BTU/LB.	METRIC kilojoules/kilograms	KWH/kilogram
Petroleum Products			
CRUDE	18700 - 19500	43500 - 45300	4.03 - 4.19
FUEL OIL	18500 - 19400	43000 - 45100	3.98 - 4.18
KEROSENE	19800	46000	4.26
GASOLINE	20700	48100	4.45
BUTANE	21200	49300	4.56
PROPANE	21600	50200	4.65
COAL and Solid Fuels			
WOOD	3600 - 5800	8400 - 13500	.78 - 1.25
* PEAT	3500 - 10000	8100 - 23300	.75 - 2.16
* LIGNITE	5500 - 11000	12800 - 25600	1.19 - 2.37
* BITUMINOUS	11000 - 15300	25600 - 35600	2.37 - 3.30
* ANTHRACITE	11500 - 14000	26700 - 32600	2.47 - 3.02
* COKE	12000 - 14400	27900 - 33500	2.58 - 3.10
Natural Gas			
Pittsburg	21700 - 23800	50500 - 55300	4.68 - 5.12
Nuclear			
U^{235}	3.53×10^{10}	8.21×10^{10}	7600000.

From "Marks' Mechanical Engineers Handbook" 6th Edition,. except
* " The Engineers Manual", Hudson, 2nd Edition, John Wiley.

** assumes Density of .04616 LBS/ft^3.

NOMENCLATURE

AGA	American Gas Association
Btu	British Thermal Unit
CPI	Consumer Price Index
GNP	Gross National Product
KWhr	Kilowatthour
LNG	Liquid Natural Gas
Mcf	Thousand cubic feet
MWhr	Megawatthour
Qcf	Quadrillion cubic feet
QUAD	Quadrillion Btu
SNG	Synthetic Natural Gas
Tcf	Trillion cubic feet
USGS	United States Geological Survey

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